BEFORE THE

PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	DOCKET NO. 2008-0083
	)	
For Approval of Rate Increases and	)	
Revised Rate Schedules and Rules	)	
	)	

DEPARTMENT OF DEFENSE'S RESPONSES

TO PUC-IR 167, PUC-IR-168 AND PUC-IR-172.

AND

CERTIFICATE OF SERVICE

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ATTORNEYS FOR
DEPARTMENT OF DEFENSE

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DEPARTMENT OF DEFENSE'S

SUBMISSION OF INFORMATION RESPONSES

TO PUBLIC UTILITIES COMMISSION OF HAWAII.

COMES NOW, DEPARTMENT OF DEFENSE by and through its undersigned attorney and

hereby submits its Responses to PUC-IR-167, PUC-IR-168 and PUC-IR-172 to the Public Utilities

Commission of Hawaii.

DATED: Honolulu, Hawaii, 20 OCT , 2009.

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ATTORNEY FOR
DEPARTMENT OF DEFENSE

PUC-IR-167   Please provide a full and detailed narrative explanation of why all cost increases in the proposed Settlement Agreement were on a per-kWh basis rather than on a percentage basis for all revenues.

Response: The only aspect of the settlement that initially was on a per kWh basis was the intra-class rate design for the interim increase. The overall increase for each individual rate schedule was a percentage increase to each rate schedule. Within each rate schedule, one of the parties had proposed that the interim increase be applied on a per kWh basis, and no other party objected.

Ultimately, as a result of the Commission's Interim Order, the parties agreed to implement the interim increase within each rate schedule as a uniform percentage to all charges within the rate schedule.

Respondent: Maurice Brubaker, BAI Associates

PUC-IR-168   Please describe all reasons why the rate increase resulting from this rate case should or should not be allocated to both the fixed and per-kWh components of rates.

Response: DOD will address only the large power schedules in its comments. These schedules are Large Power Secondary (PS), Large Power Primary (PP) and Large Power Transmission (PT) in the present tariffs. In the settlement tariffs, the parties agreed to separate the directly served customers on Schedule PP and combine them with Schedule PT customers in a new schedule known as Direct Served, or DS. The remaining customers are consolidated on Schedule P with appropriate voltage credits.

As a result of this more precise differentiation among customers, the rates were restructured to change the declining block demand charges to a single demand charge for each rate schedule, and to change the current "hours use" energy charges to a single flat per kWh charge for each rate schedule. The goal of this

rate design is to move the demand and energy charges closer to the demand costs and energy costs, respectively, as determined in the class cost of service study. Accordingly, all elements of the demand and energy charges in these rates were modified in order to produce rates that are more cost-based than the current rates.

◆ Respondent: Maurice Brubaker, BAI Associates

PUC-IR-172   How should HECO's ROE reflect the presence or absence of each of the

following?

a)   Decoupling

b)   The Revenue Adjustment Mechanism

c)   The REIP Surcharge

d)   The Power Purchase Adjustment Clause

Please provide a narrative description and as much quantification of your answer

as possible.

Response: All of the aspects of the Hawaii Clean Energy Initiative (HCEI), enumerated above, reduce the operating risk of HECO. DOD witness Hill discusses each of those aspects in his Direct Testimony at pages 5 through 8.

Decoupling revenues from sales has the most profound reduction in risk for HECO because that rate setting mechanism shields the Company from revenue volatility and risk due to weather, economic conditions and customer conservation. Because the Hawaiian economy is dependent on tourism, HECO's revenues are inordinately sensitive to fluctuations in the economic climate. The institution of a decoupling regime in Hawaii will substantially lower the Company's operating risks because it will not be subject to declining revenues related to economic down-turns (such as the current recession). That is because the revenues determined necessary in a rate proceeding will be recovered through the Revenue Adjustment Mechanism rather than producing a revenue short-fall (as would be the case in the current regulatory regime). A more stable (less volatile) revenue stream produces a more stable net income stream to stockholders and, thus, a less risky investment.

Also reducing risk to investors are adjustment mechanisms that allow the utility to adjust rates to recover actual costs incurred, rather than simply setting rates based on expected cost levels, and/or allow cost recovery to happen more quickly than under traditional regulation. The Revenue Adjustment Mechanism (in addition to

implementing the decoupling adjustment) allows the automatic recovery of changes in federal or state tax rates. The Clean Energy Infrastructure Surcharge (CEIS) will be rolled into the Renewable Energy Infrastructure Program (REIP) and expedite cost recovery of renewable energy or grid efficiency infrastructure. The Power Purchase Adjustment Clause will allow the Company to recover (monthly) all reasonably incurred purchased power costs (including capacity, operating and maintenance expenses) through an automatic adjustment mechanism rather than through a base rate case, as they are now.

While DOD witness Hill did not quantify the ROE impact of each of the elements of HECI set out in the interrogatory, he notes that the allowed return for HECO with HECI should be lower than it would have been under traditional regulation:

> With reduced risk, the rate of return allowed the Company should also be lower than it would have been absent HCEI. This should not be construed as any sort of negative aspect of a truly innovative approach to future energy supply and use, but rather a rational assessment of risk and return. An income stream that is less volatile is less risky and should be afforded a lower return—it is just that simple.
>
> However, rather than attempt to project any precise "basis point" impact of HCEI, I believe its risk-reducing aspects can be appropriately recognized by this Commission shifting its view of HECO as an above-average risk utility to one that, with HCEI, has lower-than-average risk. As such, after the Commission determines a reasonable range for the cost of equity for HECO, it would be appropriate to utilize the lower portion of that range when awarding an allowed return. In allowing HECO a lower level of profit that it would have absent HCEI, the Commission would fulfill its obligation to provide the Company a reasonable opportunity to earn an appropriate risk-adjusted return, while providing Hawaii ratepayers some of the benefits arising from the lower operating risks afforded HECO by the public/private partnership newly codified in the HCEI agreement. (DOD T-2, pp. 8)

While a detailed assessment of the risk reduction and equity cost impact of each of the HECI elements enumerated in the interrogatory was beyond the scope of Mr. Hill's testimony on behalf of DOD in this proceeding, he was recently retained to perform such an analysis with regard to a decoupling regime mandated in Massachusetts for Bay State Gas. His recommendation in that proceeding was for a reduction in the allowed ROE (for a decoupling regime alone) of 50 basis points. A copy of that testimony is attached.

Respondent: Stephen Hill, Hill and Associates

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that one copy of the foregoing document was duly served upon the following

parties, by personal service, hand-delivery, and/or U.S. mail, postage prepaid, and properly

addressed pursuant to HAR sec. 6-61-21(d).

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Naval Facilities Engineering Command,
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THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE
DEPARTMENT OF PUBLIC UTILITIES

BAY STATE GAS COMPANY   DOCKET NO. 09-30

TESTIMONY OF STEPHEN G. HILL
ON BEHALF OF
THE ATTORNEY GENERAL

June 30, 2009

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DIRECT TESTIMONY
STEPHEN G. HILL

DOCKET NO. 09-30

BAY STATE GAS COMPANY

TESTIMONY OF STEPHEN G. HILL

1 ## INTRODUCTION / SUMMARY

2

3 Q. Please state your name, occupation and address.

4 A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal

5   of Hill Associates, a consulting firm specializing in financial and economic issues in

6   regulated industries. My business address is P.O. Box 587, Hurricane, West Virginia,

7   25526 (e-mail: sghill@compuserve.com).

8

9 Q. Briefly, what is your educational background?

10 A. After graduating with a Bachelor of Science degree in Chemical Engineering from

11   Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane

12   Graduate School of Business Administration at Tulane University in New Orleans,

13   Louisiana. There I received a Master's Degree in Business Administration. I have been

14   awarded the professional designation "Certified Rate of Return Analyst" by the Society

15   of Utility and Regulatory Financial Analysts. This designation is based upon education,

16   experience and the successful completion of a comprehensive examination. I have also

17   been on the Board of Directors of that national organization for several years. A more

18   detailed account of my educational background and occupational experience appears in

19   Appendix A.

20

21 Q. Have you testified before this or other regulatory commissions?

22 A. In the twenty-five years that I have been an expert cost of capital witness I have not

23   testified in this jurisdiction. However, I have testified on cost of capital, corporate

24   finance and capital market issues in more than 250 regulatory proceedings before the

25   following regulatory bodies: the West Virginia Public Service Commission, the

26   Pennsylvania Public Utilities Commission, the Oklahoma State Corporation Commission,

27   the Public Utilities Commission of the State of California, the Texas Public Utilities

28   Commission, the Maryland Public Service Commission, the Public Utilities Commission

1   of the State of Minnesota, the Ohio Public Utilities Commission, the Insurance

2   Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the

3   Rhode Island Public Utilities Commission, the City Council of Austin, Texas, the Texas

4   Railroad Commission, the Arizona Corporation Commission, the South Carolina Public

5   Service Commission, the Public Utilities Commission of the State of Hawaii, the New

6   Mexico Corporation Commission, the State of Washington Utilities and Transportation

7   Commission, the Georgia Public Service Commission, the Kentucky Public Service

8   Commission, the Public Service Commission of Utah, the Illinois Commerce

9   Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory

10   Commission, the Virginia Corporation Commission, the Montana Public Service

11   Commission, the Public Service Commission of the State of Maine, the Public Service

12   Commission of Wisconsin, the Vermont Public Service Board, the Federal

13   Communications Commission and the Federal Energy Regulatory Commission. I have

14   also testified before the West Virginia Air Pollution Control Commission regarding

15   appropriate pollution control technology and its financial impact on the company under

16   review and have been an advisor to the Arizona Corporation Commission on matters of

17   utility finance.

18

19   O. On behalf of whom are you testifying in this proceeding?

20   A. I am testifying on behalf of the Attorney General of Massachusetts (AG).

21

22   Q. What is the purpose of your testimony?

23   A. The primary focus of my testimony in this proceeding is to quantify the cost of capital

24   impact of the revenue decoupling rate mechanism proposed by Bay State Gas Company

25   (BSGC, Bay State, the Company). Decoupling the revenues earned by the Company

26   from its volumetric gas sales will reduce the volatility of the Company's revenues and net

27   income, lowering its operating risk; and, because risk and return are directly related,

28   lower operating risk indicates a lower investor-required return and, therefore, a lower

1   allowed return. This fact was recognized by the Department in its Order in D.P.U. 07-50-

2   A:

3

4   Decoupling is designed to ensure that distribution
5   companies' revenues are not affected by reductions in
6   sales, and do not increase from undue increases in sales.
7   See D.P.U. 07-50, at 1-2. Thus, by definition, decoupling
8   reduces volatility (See Concentric Reply Comments at 2;
9   Attorney General Reply Comments at 16-17). Assuming
10   everything else remains the same, such reduction in
11   earnings volatility should reduce risks to shareholders and,
12   thereby should serve to reduce the required ROE. (Order in
13   Docket D.P.U. 07-50-A, July 16, 2008, pp. 72, 73)

14

15   My testimony provides a quantification of how much the allowed return on equity

16   should be reduced to account for the lower risk imparted by decoupling and addresses the

17   shortcomings of Company witness Hevert's analysis of the impact of decoupling. I will

18   also briefly address two additional aspects of the Company's testimony in this

19   proceeding: 1) Mr. Hevert's comments regarding the recent financial crisis and its impact

20   on the cost of capital, and 2) Mr. Moul's "leverage" adjustment to the cost of equity

21   capital.

22

23   Q. Have you prepared an Exhibit in support of your testimony?

24   A. Yes, Exhibit_(SGH-1) consists of 4 Schedules and provides the analytical support for the

25   conclusions reached regarding the cost of equity impact of decoupling presented in the

26   body of the testimony. This Exhibit was prepared by me and is correct to the best of my

27   knowledge and belief.

28

29   Q. Please summarize your testimony and findings in this proceeding.

30   A. My testimony is organized into two sections. In the first section, I discuss the reasons

31   why decoupling reduces revenue and income volatility and why that reduction in

32   volatility necessarily implies a reduction in the allowed return on common equity. My

1   testimony does not consider the appropriateness of the proposed decoupling mechanism

2   for BSGC—other witness for the Attorney General will address that topic. However,

3   through an analysis of the Company's historical results of operations, I examined the

4   components that have actually contributed to BSGC's revenue and income volatility and,

5   using conservative assumptions, quantify the degree to which the allowed return on

6   equity should be reduced as a consequence of the Company's decoupling proposal in

7   order to fairly balance the interests of the Company's customers and owners. In that first

8   section of my testimony I also review the analysis of the impact of decoupling proffered

9   by Company witness Hevert, underscoring the shortcomings therein.

10   I have estimated the equity capital cost of the Company's gas utility operations

11 should be reduced by at least 50 basis points to account for the reduction in operating risk

12 afforded by decoupling. In the alternative, the Company's ratemaking common equity

13 ratio could be reduced to affect the same reduction in return that would be created by at

14 least a 50 basis point reduction in the cost of equity.

15   In the second section of my testimony, I respond briefly to Company witness

16 Hevert's discussion of the current economic crisis and its impact on the cost of common

17 equity capital. I also briefly discuss the problems contained in the "leverage" adjustment

18 to the cost of equity capital included in the cost of equity recommendation of Company

19 witness Paul Moul.

20

21 Q. What is the basis for the proper allowed rate of return for a regulated firm?

22 A. Although I am not an attorney and do not offer any legal opinion here, it is my

23   understanding as a rate of return expert that the Supreme Court of the United States has

24   established, as a guide to assessing an appropriate level of profitability for regulated

25   operations, that investors in such firms are to be given an opportunity to earn returns that

26   are sufficient to attract capital and are comparable to returns investors would expect in

27   the unregulated sector for assuming the same degree of risk. The Bluefield and Hope

28   cases provide the seminal decisions [Bluefield Water Works v. PSC, 262 US 679 (1923);

1   FPC v. Hope Natural Gas Company, 320 US 591 (1944)]. These criteria were restated in

2   the Permian Basin Area Rate Cases, 390 US 747 (1968). However, the Court also makes

3   quite clear in Hope that regulation does not guarantee profitability and, in Permian Basin,

4   that, while investor interests (profitability) are certainly pertinent to setting adequate

5   rates, those interests do not exhaust the relevant considerations.

6   As a starting point in the rate-setting process, then, the cost of capital of a

7   regulated firm represents the return investors could expect from other investments, while

8   assuming no more and no less risk. Since financial theory holds that investors will not

9   provide capital for a particular investment unless that investment is expected to yield the

10   opportunity cost of capital, the correspondence of the cost of capital with the Court's

11   guidelines for appropriate earnings is clear.

12

13   Q. The cost of equity capital is most often estimated using a complex array of economic

14   models and algebraic formulas. Is there a simple way to understand how the concept of

15   the cost of equity capital is applied in regulation?

16   A. Yes. In a regulated rate setting context such as this, the cost of equity capital can be most

17   easily understood as the rate of profit that should be allowed for the regulated firm. A

18   firm's profit is the amount of money that remains from its revenues after it has paid all of

19   its costs—operating costs (commodity supply costs, depreciation, equipment maintenance

20   costs, salaries, fees, taxes, retirement obligations), as well as income taxes and interest

21   costs. When that rate of profit is multiplied by the amount of equity capital supporting

22   the utility's rate base, an annual dollar amount of profit to be included in a firm's revenue

23   requirement is determined. Conversely, that dollar amount of profit, divided by the

24   amount of common equity capital used to finance the firm's regulated assets produces a

25   percentage rate of return on equity. If, for example, the profit earned by a utility is

26      $10/year and investors have provided $100 of equity capital, the firm's return on equity

27   (ROE) is 10%.

28   The purpose of all of the economic models and formulas in cost of capital

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1   testimony is to estimate, using market data of similar-risk firms, the percentage rate of

2   return investors require for that risk-class of firms — in this case, gas utility operations. If

3   the profit included in the rates, as a percent of the firm's equity capital, is set equal to the

4   cost of equity capital (the investors' required return), the utility, under efficient

5   management, will be able to attract the capital necessary to maintain the firm's financial

6   integrity and the interests of investors and ratepayers will be balanced, as called for in the

7   U.S. Supreme Court cases cited above.

8   Simply put, the amount of profit a utility should be given an opportunity to earn

9   (as a percentage of the total equity investment) should be equal to the market-based cost

10   of equity capital.

11

12   **I. DECOUPLING RATE MECHANISMS – RISK AND RETURN**

13

14   **A. QUANTIFICATION OF RISK REDUCTION**

15

16   Q. Please provide an overview of the relationship between regulatory decoupling and

17   investors' perception of risk.

18   A. The decoupling mechanism (RPC or revenue-per-customer decoupling) requested by

19   BSGC in this proceeding is designed to separate revenues from volumetric sales.

20   Because decoupling a utility's base revenues from sales has the effect of reducing the

21   utility's exposure to revenue stream volatility caused by economic conditions,

22   conservation, weather or any other operating condition that would normally cause

23   revenue fluctuations, it lowers the risk of the utility. Lower operational risk for the utility

24   equals lower risk for investors and should, in turn, equate to lower allowed rates of return

25   on equity and/or lower equity ratios in the ratemaking capital structure. In this portion of

26   my testimony, I analyze the reduction in revenue volatility that Bay State will realize

27   through the adoption of a decoupling mechanism and provide an analytical framework

28   through which that risk reduction can be assessed and the equity capital cost impact

1   quantified.

2

3   Q. Please describe the relationship between volatility and risk.

4   A. An investor purchases a financial asset with an expectation that the asset will produce a

5   future stream of income, generating an expected rate of return. The risk of investing in

6   any asset is directly related to the possibility that actual returns will deviate from

7   expected returns. The greater the potential for actual returns to deviate from expected

8   returns, the higher the risk. Conversely, the more certain an investor can be that the

9   returns expected will be realized, the lower the risk.

10   One measure of the risk of a financial asset, then, is the volatility or variability of

11   the income stream or return it generates. Chart I, below, shows the income streams

12   generated by two financial assets, "Asset A" and "Asset B." Both of the assets have,

13   over time, provided a trend of increasing returns. In fact, the trend line of the returns

14   (shown as the dashed line in Chart I) is exactly the same for both investments. Therefore,

15   given that conditions in the future could be expected to resemble those of the past,

16   investor would, on average, expect that the dollar returns produced by each investment to

17   be the same in future periods. The risk of the two assets is not the same, however.

18

1

2   Chart I.

3   Volatility and Risk

4
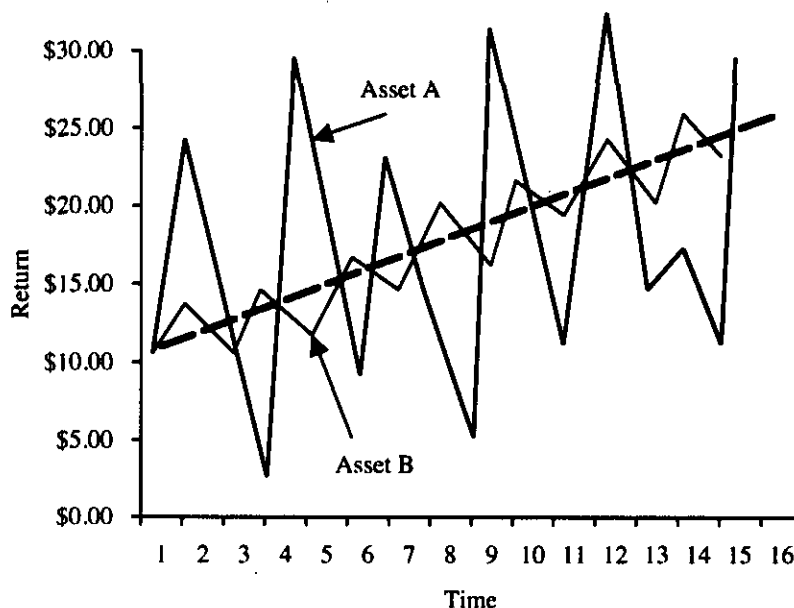
5   Asset A has shown much wider swings in return, much greater volatility, than has

6 Asset B. Therefore, even though Asset A has the same expected future income stream as

7 Asset B, there is a much lower probability that the actual return realized from an

8 investment in Asset A will equal the expected return. Asset A, then, is a riskier

9 investment than Asset B, which, in all probability, will provide a return to investors that

10 more closely approximates that expected.

11   When an investor purchases a share of utility stock, he or she is purchasing an

12 expected future stream of income in the form of dividends and growth in that dividend, or

13 capital appreciation when the stock is sold. That dividend expectation is, in turn,

14 dependent on the earnings of the utility. If the earnings are steady and show little

15 fluctuation, the dividend is more secure and the utility is seen by the investor as less risky

16 than an otherwise similar investment whose dividend is based on a volatile earnings

17 stream. The fact that the income stream volatility of a financial asset is directly related to

18 its investment risk is neither controversial nor difficult to comprehend, but that concept is

1   fundamental to assessing the risk impact of decoupling. A decoupling mechanism like

2   that requested by the Company in this proceeding works to reduce the income stream

3   volatility of the utility's operations and, thus, its operating risk.

4

5   Q. Please explain how a decoupling mechanism works to reduce a utility's revenue

6   volatility.

7   A. A decoupling mechanism separates utility revenues from unit sales—kWh in the case of

8   an electric utility and Mcf or dekatherms in the case of a gas utility—and targets, instead

9   an overall revenue requirement. Under the Company's proposal, if customer

10   consumption is below the expected level and revenues do not meet the projected level,

11   the utility is allowed to increase unit rates in order to produce the projected revenue level.

12   If, on the other hand, revenues exceed the target level, the utility is required to return to

13   customers the amount of revenues that exceed the target level.

14   However, in the decoupling ratemaking regime proposed by BSGC, there is no

15   mechanism for discerning the source of the change in customer usage. The reduction in

16   usage may come from conservation, or it may come from lower customer usage due to

17   factors unrelated to conservation, e.g., economic downturns, price elasticity effects on

18   demand, changes in the firm's customer mix, technological changes, or weather-related

19   factors. Because there is no practical way to distinguish the various factors that may

20   affect customer usage, all the factors that could impact unit sales are necessarily included

21   in the decoupling/make-whole process. In effect, the decoupling the Company requests

22   acts as a regulatory pass-through, much like a fuel-adjustment clause for variations in

23   base revenues. Therefore, the decoupling process can operate a buffer for the utility,

24   sheltering its stockholders from fluctuations in revenues and, ultimately, moderating

25   swings in operating earnings from a multitude of causes that might otherwise arise from

26   unfavorable conditions.

27   If, through a decoupling ratemaking process, the utility is made whole for

28   operational variables that can negatively affect revenues and earnings, the potential for

1   volatility is greatly reduced. Investors and investor advisory services are aware that a

2   reduction in the income stream volatility reduces the overall investment risk of a utility

3   operation. As Company witness Hevert points out at page 44 of his Direct Testimony in

4   this proceeding, Moody's indicates that decoupling enables utilities to maintain bond

5   ratings in the face of adversity.

6

7   "LCDs that have, or soon expect to have, RD [Revenue

8   Decoupling] stand a better chance than others in being able

9   to maintain their credit ratings or stabilize their credit

10   outlook in the fact of adversity." (Moody's June 2006,

11   Special Report on Revenue Decoupling and Local Gas

12   Distribution Companies)

13

14   Therefore, the removal of the income volatility and risk associated with those factors

15   indicates that a utility operating under a decoupling mechanism has a lower investor-

16   required return on equity than an otherwise equivalent utility operating under traditional

17   regulation (i.e., without a decoupling mechanism).

18   Decoupling lowers a utility's operating risk and unless that lower operating risk is

19   reflected in rates through a reduction in the authorized rate of return or some other

20   appropriate measure, decoupling will produce a windfall for utility investors. Instituting

21   a decoupling program for utilities without a concomitant downward adjustment to the

22   allowed equity return, then, would create utility rates that exceed costs. Such rates would

23   exceed just and reasonable levels and also would encourage an economically inefficient

24   allocation of resources. Therefore, the allowed return on equity for a utility that is

25   entering a regulatory framework in which revenues are decoupled from volumetric sales

26   must be lower than that appropriate for the same utility under traditional regulation. The

27   question of primary importance here is—how much lower?

28

29   Q. How should the Department approach this issue of quantifying this reduction in risk?

30   A. An analytical process through which the impact of decoupling on the appropriate return

31   on equity for Bay State can be assessed is presented below, however, it is intuitively

1   obvious that the more the utility's revenue and income volatility are dependent on factors

2   that will be obviated by decoupling, the greater the risk reduction caused by decoupling

3   and the lower the allowed equity return should be. If, for example, operating costs were

4   constant and 100% of the revenue variations of a utility were due to factors eliminated by

5   decoupling, that ratemaking mechanism could effectively turn a utility equity investment

6   into a bond-like financial instrument. In that extreme instance, the level of uncertainty

7   regarding the expected return that normally accompanies a utility equity investment

8   would be substantially reduced and an appropriate equity return would fall toward that

9   appropriate for utility debt capital.

10

11 Q. Is there a regulatory case recognizing reduced volatility by lowering the allowed return

12   on equity?

13 A. Yes. In Opinion No. 281 [40 FERC ¶61,117 (July 31, 1987), Allegheny Generating

14   Company, FERC Docket Nos. EL86-37 and EL86-38], the Federal Energy Regulatory

15   Commission ordered that the cost of equity capital of a FERC-regulated generation

16   subsidiary of an investor-owned utility be set below the cost of equity capital for the

17   utility. FERC determined that, due to the reduced risk, the allowed return should be set at

18   a point below the average cost of equity for similar –risk investor-owned electrics and

19   above BBB-rated utility bond yields. The reason for the reduction in the cost of equity

20   award was the fact that the generation subsidiary collected rates under a FERC tariff in

21   which the return on equity was collected each month as an expense and, as a result,

22   showed considerably less variability than the equity return of its parent company. In the

23   current market environment, in which the cost of equity capital is approximately 9.5%[1]

24   and the current yield on BBB-rated utility debt is approximately 7%, the FERC's method

25   would produce a return on equity of 8.25% [(9.5% + 7%)/2)].

26   While FERC's current stance on what constitutes an appropriate level of profit

---

26

[1] Over the past two years, my cost of capital analyses have indicated that, for both gas and electric utilities, the cost of equity capital has ranged between 9% and 10%.

1   (return on equity) has shifted to one that focuses on incentives to encourage plant

2   construction, its prior position on the impact of volatility on the cost of equity capital is

3   both theoretically sound and instructive with regard to the task undertaken here. The

4   8.25% equity return estimated using the FERC methodology cited should be considered a

5   lower bound for the impact of a equity cost reduction in this proceeding. That is because,

6   while a decoupling rate mechanism will reduce BSGC's revenue and income volatility, it

7   will not eliminate it altogether and the risk reduction imparted, therefore, will be less than

8   that embedded in the FERC rate structure at the core of the cited decision and the

9   decrement to the allowed return should be less severe.

10

11 Q. Please explain how the risk reduction afforded by a decoupling regulatory regime can be

12 quantified.

13 A. Quantifying the change in operating risk of a utility operation due to a reduction in

14 revenue and income volatility caused by a decoupling mechanism is a two-step process.

15 First, the degree to which fluctuations in utility revenues are dependent on operating

16 factors such as weather and the economy must be measured and, second the revenue

17 volatility that normally exists with the utility operation is quantified.

18   Measuring the degree to which fluctuations in utility revenues are dependent on

19 changes in the operating environment is accomplished through multi-factor regression

20 analysis. In such an analysis, variables that represent weather (heating degree days);

21 economic conditions (economic index for Massachusetts or unemployment) and seasonal

22 factors are regressed against the utility's quarterly revenues over a relatively long time-

23 frame. Through such an analysis, it can be determined to what degree revenues are

24 determined by those operating variables.

25   For Bay State Gas, I requested that the Company provide financial statements,

26 and heating degree day data each quarter over the past ten years (1999-2008). The

27 Company was able to provide those data from 2002 forward. I also was able to obtain

28 annual data from 1999-2008 from the Annual Return reports filed by the Company with

1   the Department. For the economic variable in the analysis of annual data, I utilized

2   Massachusetts Gross State Product (GSP), which is available on the U. S. Department of

3   Commerce, Bureau of Labor Statistics web page (those data are not provided by quarter).

4   For the analysis of quarterly net revenue volatility, I utilized seasonally-adjusted

5   unemployment in Massachusetts as a proxy for the economic health of BSGC's service

6   territory. For quarterly revenues I also included a heating-season variable ("1" during the

7   4th and 1st quarter and "0" during the 2nd and 3rd quarter of each year) to account for the

8   fact that the quarterly revenues of a gas utility vary according to seasonal heating needs. I

9   used net revenues (revenues less gas costs) as the dependent variable in the analysis in

10   order to remove revenue fluctuations due to gas cost volatility and because changes in gas

11   costs are already accounted for by the Company's purchased gas adjustment procedures,

12   which will not be affected by decoupling.

13   Regressing those variables cited above that affect the Company's operating

14   environment against its annual net revenues from 1999 through 2008 and its quarterly

15   revenues from 2002 through 2008 indicates that fluctuations in weather, and economic

16   factors account for approximately 90% of the volatility in the Company's revenues

17   (Schedule 1, pages 1 and 2). Page 1 of Schedule 1 (annual data) shows that both

18   economic activity and weather (heating degree days—HDD) are important factors in

19   determining BSGC's revenue volatility, and both were statistically significant in their

20   impact on net revenues. The coefficients of each of those factors were statistically

21   significant at above the 99% level (t-statistic > 3.5) and the chance that the correlations

22   indicated are random is very small, as indicated by the F-statistic (36.63; probability =

23   0.016%). Page 2 of Schedule 1 shows that economic, weather and seasonal factors

24   explained approximately 92% of BSGC's net revenue volatility. In this analysis, both

25   heating degree days and the heating-season index were statistically significant at above

26   the 95% level, while the economic variable (percent unemployment in Massachusetts)

27   produced a lower t-statistic and is statistically significant at the 85% level. Again, the F-

28   statistic indicates a very low probability that the correlations shown are random.

1   Finally it should be noted that there was some degree of autocorrelation with

2   these data. The Durbin-Watson (DW) test for the annual data was inconclusive because

3   there is only 10 years of data and, therefore, it is reasonable to make the conservative

4   assumption that some autocorrelation of the data exist. Also, while the DW result for the

5   quarterly net revenue analysis (1.38) was within acceptable limits, the coefficient was

6   relatively low, again indicating that it is reasonable to assume that some autocorrelation

7   does exist. However, the results of this analysis are not being used to attempt to project

8   the Company's revenues in a future period. In that situation, autocorrelation, which is the

9   correlation of the predicted variable with its own residuals (the differences between the

10   actual data and the projected data), can cause a projection based on such data to be

11   unreliable. In the analysis presented here, we are not attempting to pinpoint BSGC's

12   revenue in any future period. Rather, we examine the actual historical relationship

13   between revenue stream volatility, weather, and economic factors in order to determine

14   the extent to which factors that influence unit sales determine the Company's revenue

15   volatility. The historical relationship described above will be altered because decoupling

16   eliminates the impact of those factors on revenue volatility, and the historical volatility

17   will be reduced. Based on the historical relationship shown in these analyses, an estimate

18   can be made of the impact of reduced revenue volatility.

19

20   Q. Are there other factors that should be considered in assessing to what degree the

21   operating parameters you have identified control the volatility in the Company's revenues

22   and income and, thus, its investment risk?

23   A. Yes. First, it is important to note that linear regressions are relatively simple

24   approximations of reality and to the extent that changes in the Company's revenues have

25   occurred in a more complex, non-linear fashion, they may not be fully captured in such

26   an analysis. Second, this analysis (especially the analysis of revenue volatility) captures

27   the total investment risk differences that may arise due to the implementation of a

28   decoupling mechanism. However, according to theory, investors are primarily concerned

| 1 | with the systematic, or non-diversifiable risk of an investment, not the total risk. |
2	Therefore, it is unlikely that investors will respond to the differences in total risk captured
3	in this analysis because some portion of that risk can be diversified away.
4	The amount of diversifiable risk as a percentage of total risk is not readily
5	determinable, but because the majority of the volatility in both revenues and income are
6	weather-related and the weather deviates from the norm in a random fashion, it is not
7	reasonable to believe that substantial amounts of the risk differences derived here could
8	be diversified away. One could also make the case that whatever diversification that can
9	be made vis a vis an investment in Bay State (especially the weather- and economy-
10	related aspects) has already been made, and new opportunities for significant additional
11	diversification will not arise as a result of the institution of a decoupling mechanism.
12	Finally on this point, beta coefficients (which are designed to capture the systematic, non-
13	diversifiable risk of a stock) have relatively low "r-squared" values. Therefore, although
14	theory indicates that investors' only concern is systematic risk, in reality beta coefficient
15	explain a relatively small amount of the volatility of stock prices for a particular security
16	and, thus, are likely not representative of the only risk factor considered by investors.
17	In sum, while the statistical results of the volatility analyses presented herein lend
18	credence to their reliability, it is important to remember that we are estimating the impact
19	of decoupling on volatility and risk, and that investor may not include all of that risk
20	reduction in the price they are willing to provide for Bay State (through its parent).
21	Therefore, in estimating the average dollar/cost of equity impact of decoupling on BSGC,
22	I will utilize a conservative factor of 50% for the impact of the operating variables
23	studied, rather than the 90% factors that appear in the statistical results. In other words,
24	in quantifying the risk impact of the reduction in revenue and income volatility afforded
25	Bay State by decoupling, I will assume that the variance of the Company's revenues will
26	be reduced by only 50% rather than the 90% levels indicated in the respective regression
27	analyses. In my view, this is a conservative adjustment, which may result in an
28	understatement of the equity return decrement occasioned by decoupling that is necessary

1   to balance the interests of investors and ratepayers.

2

3 Q. Now that the impact of the operating parameters on the volatility of the Company's

4   revenue stream has been estimated, what is the second step in estimating the cost of

5   capital impact on the Company?

6 A. Regression analysis also plays a part in quantifying the income stream volatility that

7   normally exists with the utility operation. Chart II, below, shows the revenue stream of a

8   hypothetical utility operation over time. Also show in Chart II is the least-squares linear

9   regression line, which represents the trend in revenues over that time period. In addition,

10   the variance and standard deviation of the revenues around the trend line can be

11   calculated. That process gives a quantitative measure of the volatility of the utility's

12   revenues around the revenue trend or regression line. Similar graphs of Bay State's net

13   revenues over the 1999—2008 annual period and 2002—2008 quarterly period are shown

14   in Schedule 2, pages 1 and 2, respectively.

15   Chart II

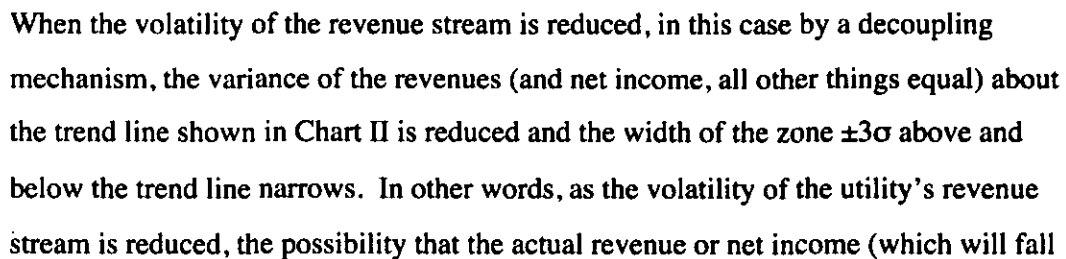16   Linear Regression of Historical Revenues

17
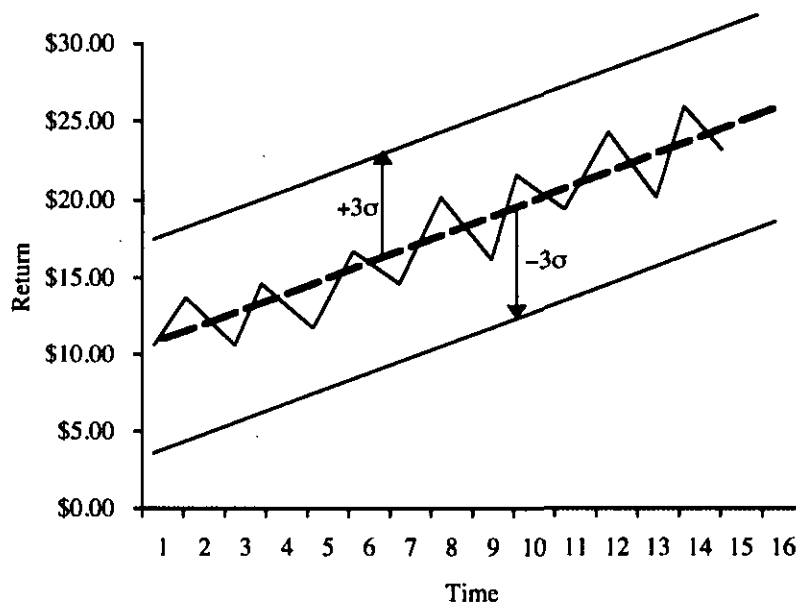
1   Once the standard deviation of revenues about the trend line is established, a zone

2   ±3 standard deviation units (σ) above and below the revenue trend line can be

3   established. Assuming the utility's revenues are normally distributed about the revenue

4   trend, a zone ± 3σ above and below the revenue trend line establishes a range within

5   which the utility's revenues will fall 99.9% of the time. For Bay State, the calculation of

6   the trend line as well as the distribution about the trend line for net revenues for the

7   annual series is shown in Schedule 3.

8   The distribution of net revenues about the historical trends can also be represented

9   as the familiar bell-shaped curve shown below in Chart III.

10

11   Chart III

12   Revenue Distribution Under Traditional Regulation

13

14   When the volatility of the revenue stream is reduced, in this case by a decoupling

15   mechanism, the variance of the revenues (and net income, all other things equal) about

16   the trend line shown in Chart II is reduced and the width of the zone ±3σ above and

17   below the trend line narrows. In other words, as the volatility of the utility's revenue

18   stream is reduced, the possibility that the actual revenue or net income (which will fall

1   within ±3σ) will more closely approximate the expected revenue or net income

2   (represented by the trend line) is increased and, therefore, the utility's operating risk is

3   reduced. Further, as the volatility of the utility's revenues (or net income) around the

4   trend line is reduced, the shape of the "bell curve" graph of the revenue distribution

5   changes. As shown in Chart IV, while still centered on the average expected revenue, the

6   "bell" formed by the distribution of utility revenues under decoupling becomes taller and

7   thinner.

8

9   Chart IV

10   Revenue Distribution Differential With Decoupling
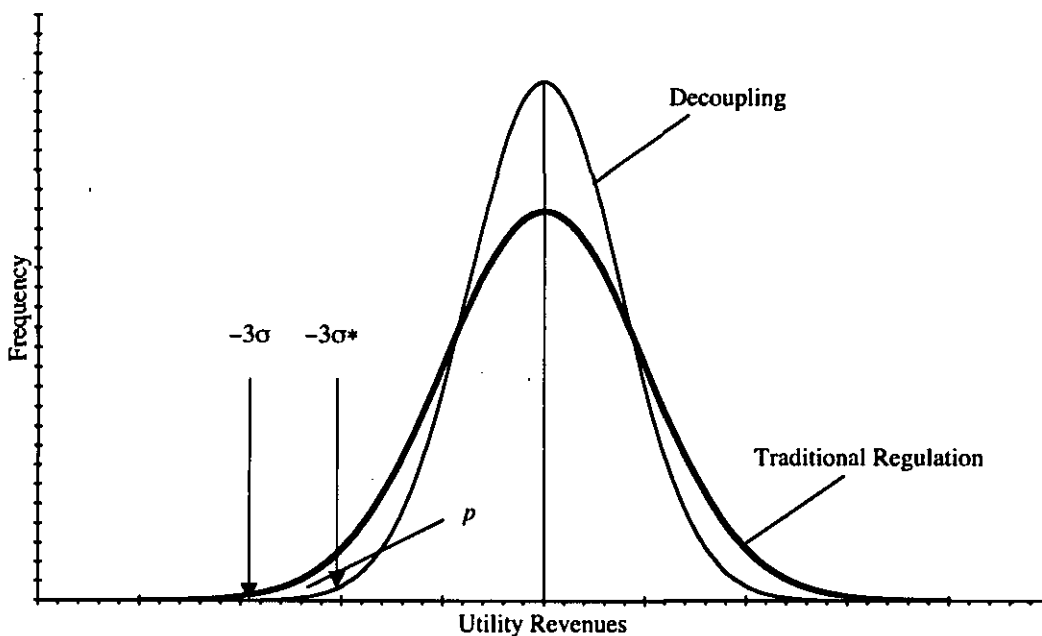
11

12   It is through this change in the shape of the distribution of possible revenue

13   outcomes, shown in Chart IV, that we are able to quantify the impact of decoupling on

14   the cost of equity capital impact of decoupling. When the variance of revenues (or net

15   income) about the trend line is reduced, the possibility of more extreme outcomes both

16   negative and positive, are eliminated. To the investor, the risk-reducing aspect of this

17   change is the elimination of the possibility of extreme negative revenue outcomes. Under

18   "traditional" regulation it is possible that the utility could experience revenues (or net

1   income) at the extreme lower left corner of the original revenue distribution (-3σ). This

2   would represent an adverse risk outcome to the investor. Under a less volatile decoupling

3   scenario, however, the revenue distribution is narrower, the expected revenues more

4   certain and the most negative outcome ($-3\sigma^*$ on the new bell curve) is a higher revenue

5   (or net income) value and, thus, represents less risk to the investor.

6   The pertinent difference in the probability outcomes under the "traditional" and

7   decoupling scenario can be quantified as the difference in the area in the graph between

8   the two curves, i.e., between -3σ and $-3\sigma^*$. This area (designated as "p" in Chart IV)

9   between the original distribution curve and the new (decoupling) curve represents the

10 reduction in the probability of an extreme negative outcome that existed prior to the

11 adoption of decoupling. As shown in Schedule 4, the probability differential ("p")

12 represented by a conservative 50% reduction in historical revenue or net income variance

13 equals approximately 0.015, which represents approximately 1.5% of revenues.

14   This means that investors would be indifferent between "traditional" regulation

15 and decoupling if the equity return under decoupling produced a revenue requirement

16 1.5% less that that under "traditional" regulation. In order for the equity return interests

17 of investors and ratepayers to be balanced under a decoupling-type regulatory regime, the

18 allowed return will have to be less than that allowed under traditional regulation. In this

19 instance, the appropriate reduction in equity return is estimated as the equity return

20 difference that would reduce revenues or net income by 1.5%, on average, based on

21 BSGC's historical results over the past ten years.

22

23 Q. Did you apply the type of analysis you described to Bay State Gas?

24 A. Yes.

25

26 Q. What are the results?

27 A. Schedule 4 shows the calculations necessary to quantify the risk-reduction impact of Bay

28   State's decoupling mechanism with regard to the Company's net revenues. Schedule 4

1   indicates, as noted above, that the probability of extreme negative outcomes in BSG's

2   revenues is reduced by about 1.5% when the Company's historical revenue variance is

3   reduced by the 50% factor I derived previously. When this percentage is multiplied by

4   Bay State's average annual net revenues over the past ten years ($183.6 Million), the

5   result is approximately $2.7 Million annually. Again, due to the risk-reducing nature of

6   decoupling, investors would be indifferent between Bay State realizing an average $183

7   Million per quarter as it has under traditional regulation and receiving $2.7 Million less

8   than that amount annually under a decoupling regulatory framework.

9   This annual reduction in revenues is translated in to an equity return differential

10   by first estimating that during the 10-year study period, Bay State's utility rate base

11   averaged $375 Million and its common equity ratio averaged 53%. In estimating the

12   Company's average rate base over the 1999-2008 period, I utilized the balance sheets

13   provided on the Company's Annual Return filed with the Department. Subtracting, in

14   each year, accrued depreciation and amortization, and intangible plant from the year-end

15   utility plant balances the Company's plant balance averaged $379,402,098. As a check

16   of that amount. I compared the amount of the Company's rate base approved in Docket

17   NO. 05-27-A ($393,345,772) with that requested four years later in this proceeding

18   ($468,706,594), and determined that those point-in-time measures indicate an annual

19   growth in Bay State's rate base of $18.840 Million. Reducing the Company's currently-

20   requested rate base by $18.8 Million annually over the past ten years indicates an average

21   value for BSGC's rate base of $365,085,464. Therefore, for purposes of analysis here, I

22   have elected to use a 10-year average rate base estimate for Bay State of $375 Million.

23   With regard to the average capital structure, based on the Company's Annual

24   Return reports during the time period in which the Department began to calculate a

25   reduction to Bay State's common equity ratio to account for the acquisition adjustment

26   (2003-2008), the average common equity ratio based on utility equity and long-term debt

27   was 61.4% and the average based on total capital (i.e., including short-term debt) was

28   44.7%. The average of those amounts is 53.0%, which happens to be quite similar to the

1   capital structure approved in the Company's last rate proceeding and that requested in the

2   instant case. Therefore, for purposes of analysis here, I will use an equity ratio estimate

3   of 53.0%.

4   Given the historical record established by the Company, a 1% reduction in equity

5   return over the historical period studied would, on average, have resulted in an annual

6   revenue reduction of $3.06 Million (1% x 53% (equity ratio) x $375 Million (Rate Base)

7   ÷ (1-35% tax rate). Therefore if an appropriate return adjustment for decoupling calls for

8   a reduction of $2.87 Million in annual revenues (as noted above and shown on Schedule

9   4), and a 1% reduction would have caused a revenue reduction of about $3.06 Million,

10 then an equity return adjustment of 94 basis points would be indicated under a decoupling

11 regime (1% x $2.87 Mill./$20 Mill.).

12   I have also performed a sensitivity analysis and examined the impact of different

13 assumptions regarding the reduction of BSGC's net revenue volatility. If, for example,

14 the volatility reduction imparted by decoupling is less than the 50% I have assumed, the

15 appropriate decrement to the cost of equity would, of course, be less. If net revenue

16 volatility is reduced by 40%, the analysis indicates an appropriate reduction in the

17 allowed return on equity of 56 basis points. If the volatility reduction is only 20%, then

18 the appropriate ROE decrement indicated by my analysis declines to 15 basis points. It is

19 important to note that the variables that affect Bay States revenue volatility, which will be

20 eliminated by decoupling, account for 90% of that volatility, and, therefore, my

21 assumption of a 50% reduction in volatility is as I have noted previously, conservative.

22 Nevertheless, I present the sensitivity analysis for the Department's information.

23   Finally, it is also noteworthy that some of the volatility reduction that will be

24 imparted by decoupling is related to the impact of weather on the Company's revenues

25 and because many of the companies in the regulated portions of the gas holding

26 companies used to estimate the cost of equity have weather normalization clauses, some

27 weather-related risk reduction will likely be captured by investors and included in the

28 stock prices they are willing to provide for those companies. Therefore, while a 94 basis

1   point decrement would be appropriate for Bay Sate in comparison to its own operational

2   history (i.e., one without a weather normalization adjustment), in comparison to the other

3   gas companies used to estimate the cost of equity, 94 basis points would tend to overstate

4   the relative reduction in risk. Therefore, for purposes of recommending a point-estimate

5   for an appropriate equity return decrement related to decoupling utility revenues from

6   unit sales, I recommend the Department use 50 basis points. If, for example, the

7   Department determines that a reasonable allowed return for Bay State would be 10.00%

8   without decoupling, then it should be 9.50% with decoupling in place.

9

10   B. DECOUPLING – COMPANY ASSESSMENT

11

12   Q. Have you reviewed the testimony of Company witness Robert B. Hevert in this

13   proceeding?

14   A. Yes, I have. Mr. Hevert reviews the status of "revenue stabilization" mechanisms for

15   four of the seven gas companies selected by Company cost of capital witness Paul Moul

16   as similar in risk to Bay State. He also reviews the market price of those firms during the

17   time period when the "revenue stabilization" mechanisms were introduced; utility rate

18   orders addressing those mechanisms; and notes that bond rating agencies have not raised

19   the rating of any utility implementing those mechanisms. From his analysis, Mr. Hevert

20   concludes that no downward adjustment to the allowed return on equity for decoupling is

21   necessary.

22

23   Q. In your opinion, does Mr. Hevert's analysis offer conclusive evidence to the Department

24   that no downward adjustment to the cost of equity is necessary to account for the

25   proposed decoupling rate mechanism?

26   A. No, and I will outline the reasons for that opinion below. However, at the outset it is

27   import to note two things. First, contrary to his ultimate recommendation here, Mr.

28   Hevert's testimony confirms that volatility and risk are directly related (e.g., his

1   discussion of the current financial environment at page 16 of his Direct Testimony, also

2   see Mr. Hevert's response to AG-20-11) and it is unarguable that a decoupling

3   mechanism, which targets per-customer revenues and effectively operates as a make-

4   whole adjustment clause for revenues, will reduce the revenue and income volatility of

5   Bay State Gas. It is clear, therefore, that due to the implementation of a decoupling

6   regime the Company's investment risk will be lowered. Mr. Hevert's testimony

7   effectively assumes that the risk and allowed return *should* be lower as a result of

8   decoupling and proceeds to try to "find" evidence of that risk reduction in market and

9   regulatory or bond rating opinions. Therefore, the truth of the matter is that the

10   Company's risk will be lowered but the publicly-available evidence reviewed by Mr.

11   Hevert is inconclusive (i.e., diffused, indirect) at best, allowing him to conclude, I believe

12   improperly, that no equity return decrement is necessary because decoupling will have no

13   affect on the Company's operating risk.

14   Second, I freely admit that the determination of any particular value for a

15   decoupling-related equity return decrement is necessarily includes subjective judgment

16   (just as the determination of the cost of equity itself). For example in my analysis,

17   although approximately 90% of the volatility of BSGC's revenues are explained by

18   factors whose impact will be eliminated by decoupling, in determining a reasonable

19   equity decrement that captures the reduction in risk, I have assumed that decoupling will

20   reduce the Company's revenue volatility by roughly half that amount. That is a judgment

21   on my part. Therefore, I do not fault Mr. Hevert for his efforts and also agree,

22   theoretically, that if investors view a firm as instantaneously less risky than other similar-

23   risk firms they will react by raising the stock price of said firm. However, reality is

24   unlike theory, there are no pure-play gas distributors, and stock trades do not occur in a

25   vacuum absent other broad market influences. Because of those facts, real-world data are

26   often inconclusive regarding underlying changes in risk, in my experience. Therefore, I

27   believe an analysis predicated on Bay State's actual historical operating results,

28   estimating the volatility reduction afforded by decoupling provides a more reliable guide

1   to the Department regarding the treatment of the allowed return on equity than that

2   offered by Mr. Hevert in this proceeding.

3

4   Q. What are the problems with Mr. Hevert's analyses related to decoupling?

5   A. First, as shown in Table I below, the gas companies relied on as a group by Mr. Moul and

6   the sub-set of those companies studied by Mr. Hevert are not *solely* gas distributors.

7

8   Table I.

9   Moul's Gas Sample Group

10

Sample Gas Companies	Gas Revenues
AGL Resources	56%
Atmos	52%
New Jersey Resources*	30%
Northwest Natural Gas*	98%
Piedmont Natural Gas*	75%
South Jersey Industries*	58%
WGL Holdings, Inc.	59%
Overall Average	61%
Mr. Hevert's Group*	65%

Data: A.U.S. Utilities Reports, May 2009

11

12   Only 60% of the revenues for the sample group used by Mr. Moul are generated by

13   regulated gas operations, on average; and the average for the sub-set of four companies is

14   a few percentage points higher. Moreover, according to Mr. Hevert's response to AG-20-

15   24, only 62% or those regulated revenues are subject to some sort of "revenue

16   stabilization" mechanism. What this means is that a substantial portion of the revenues

17   generated by these companies are not related to gas distribution operations or are not

18   subject to revenue stabilization mechanisms. Thus, any market price impact on their

19   shares that may result from the implementation of a revenue stabilization rate mechanism

1   that applies to only a portion of the company's revenue stream would be muted by that

2   fact. Moreover, the non-distribution operations of many of those firms are related to

3   energy marketing operations that have substantially greater risk and volatility than

4   regulated gas utility operations.

5   Also utility share prices are moved by other broad economic factors such as

6   interest rates, inflation prospects, mergers, and energy commodity prices. For example,

7   in November 2006 (the revenue stabilization "implementation date" of two of the

8   companies studied by Mr. Hevert, see RBH-3, p. 1), the cost rate of short-term U.S.

9   Treasury Bills exceeded that of 20-year T-Bonds. That inversion in borrowing costs is a

10   most unusual situation—one that causes short-term debt costs for utilities to rise to

11   unexpected levels and which signals economic instability and the potential for significant

12   change in the financial markets (which materialized nearly two years later). It is difficult,

13   therefore, to gauge the favorable impact of decoupling on investment risk in an

14   environment of heightened risk attributable to prevailing market forces. Similarly,

15   another gas company studied by Mr. Hevert had an implementation date for decoupling

16   of November 2005, at which time gas commodity prices had spiked to about $11/Mcf,

17   according to data available on the New York Mercantile Exchange website.[2] It is

18   reasonable to conclude that such a substantial jump in gas futures prices would affect gas

19   utility stock prices adversely and thus mask any beneficial impact caused by the

20   introduction of any revenue stabilization ratemaking mechanism. Because of these facts,

21   the market prices of the gas firms studied by Mr. Hevert are the product of many, varied

22   factors and, again, isolating the market price impact of any one factor that impacted only

23   the regulated portion of those firms would be unlikely.

24   Second, as shown in Mr. Hevert's RBH-4, even when studying the diffused

25   market prices of the parent holding companies of the companies with rate stabilization

26   mechanisms compared to Mr. Moul's entire sample group (which, presumably, also

---

26

[2]http://futures.tradingcharts.com/chart/NG/M/?saveprefs=t&xshowdata=t&xCharttype=b&xhide_specs=f&
xhide_analysis=f&xhide_survey=t&xhide_news=f

1   includes Mr. Hevert's sub-set and holds down relative price comparisons), the relative

2   market price of Mr. Hevert's group increased around the implementation of the

3   stabilization mechanism. Page 1 of RBH-4 shows that a symmetrical view of the relative

4   stock price performance of Mr. Hevert's sub-set of companies 90 days before and 90

5   after the implementation of rate stabilization from 102% of the sample group average to

6   108% of the sample group average—a relative stock price increase. While Mr. Hevert's

7   other asymmetrical stock price data show little stock price change, they do show that the

8   sub-set of companies with rate stabilization mechanisms have lower risk than the entire

9   sample group because the relative valuations are above 100%.

10   Third, Mr. Hevert's analysis conflates many aspects of rate stabilization with

11   decoupling, as he indicates at page 36 of his Direct Testimony: "...this analysis was not

12   limited strictly to revenue decoupling mechanisms." Mr. Hevert elects to consider factors

13   such as a customer charge and block-rate structures as equivalent to decoupling by

14   grouping them all as "revenue stabilization" mechanisms. While it is true that when a

15   utility can collect more of its revenue requirement "up front" in a fixed monthly customer

16   charge and, thereby, effect some rate stabilization, such mechanisms are quite common

17   and do not serve to significantly differentiate risks between companies. However,

18   moving from a traditional ratemaking scheme in which a utility's revenues are

19   determined by the commodity units it sells to a regulatory paradigm in which the per-

20   customer revenues will be recovered regardless of the actual level of sales represents a

21   substantial reduction in operating risk. Therefore, Mr. Hevert's testimony on this point—

22   that everyone has revenue stabilization mechanisms and the institution of one more

23   (BSGC decoupling), will not be a significant change—ignores the fact that decoupling is

24   a far more powerful tool with which to stabilize revenues than something like increasing

25   the customer charge.

26   Finally on this point, in discussing revenue stabilization mechanisms, Mr. Hevert

27   fails to note that Bay State already has in place many regulatory adjustment mechanisms

28   not listed for the other companies in his sample group (e.g., ratesetting mechanisms to

1   recover lost base revenue associates with energy efficiency programs, energy efficiency

2   costs, manufactured gas plant remediation costs, low income rate subscription, pension

3   and post-retirement benefits, bad debt expense on the cost of gas, inflation indexing for

4   rates (Price Cap Rate Plans), recovery of "exogenous costs," and earnings sharing). All

5   of these "make-whole" and revenue stabilization mechanisms currently enjoyed by Bay

6   State tend to lower the Company's risk relative to the group of companies studied by Mr.

7   Hevert, and will continue to exist with the further risk reduction of decoupling, but are

8   not mentioned in his analysis.

9   In summary, while theory indicates that when risk is reduced, all else equal, stock

10   prices will rise, in reality "all else" is never "equal." Economic theory is pristine;

11   economic reality is not. Therefore, even though decoupling will reduce Bay State's

12   revenue and income volatility, it would be surprising, in a review of four gas companies

13   that are only partly regulated distribution operations and whose stock price "at

14   implementation" is affected by many different variables over different time-frames, to

15   find a measurable impact that could be attributed to the change in the manner in which

16   rates are collected. Therefore, Mr. Hevert's review of stock price and return movements

17   of the sub-set of Mr. Moul's gas company sample group must be categorized simply as

18   inconclusive and does not prove that the lower operating risk imparted by decoupling

19   does not require an equity return decrement.

20

21   Q. What are your comments regarding the other evidence cited by Mr. Hevert in support of

22   his position that no equity return reduction is necessary to account for the lower risk of

23   decoupling: regulatory decisions and bond rating agency comments?

24   A. With regard to the review of regulatory decisions, I have three points on which to

25   comment. First, because Mr. Hevert's analysis, as he, himself, notes, is not based solely

26   on decoupling but on other revenue stabilization methods, it is not clear that the

27   regulatory decisions he lists in RBH-5 address the same sort of decoupling that BSGC is

28   requesting in this proceeding. For that matter, there are always elements of regulation in

1   one jurisdiction that are different from other jurisdictions, making a determination of the

2   comparability of such mechanisms, or how the reduced risks attributed to them are

3   recognized difficult, at best. In fact, Mr. Hevert's RBH-5 shows that such differences

4   between regulatory orders exist within regulatory jurisdictions, with, for example, the

5   Arkansas commission reducing the ROE for one gas company and not for another.

6   Therefore, while other regulatory decisions should be considered, they are not necessarily

7   dispositive with regard to the particular decoupling method under consideration in the

8   instant case, or its impact on the risk reduction for Bay State Gas.

9   Second, Mr. Hevert notes that in a couple of the decisions he lists, the allowed

10   return on equity was reduced in settlement from the return initially sought by the utility

11   but no explicit quantification of the reduction was provided. He nonetheless categorizes

12   those decisions as a "no" with regard to an adjustment related to decoupling. Also in

13   response to AG-20-18, Mr. Hevert indicates that two-thirds of cases listed were settled

14   rather than fully-litigated and, for those cases that settled, it is difficult to know if there

15   was any give-and-take between the parties (including the regulators) with regard to the

16   final risk/allowed return matrix. Third, the regulators that did make an adjustment to the

17   allowed return on equity because of revenue stabilization mechanisms always made a

18   downward adjustment, confirming that revenue stabilization reduces risk and should also

19   reduce the allowed return on equity for the regulated firm.

20   With regard to the bond rating agencies, it seems clear to me, even in the quotes

21   Mr. Hevert provides in his testimony, that rating agencies recognize that reducing

22   revenue and income volatility reduces risks to bond holders.[3] That reduced volatility—

23   revenue "stabilization"—supports credit quality and affords those utilities with such

24   mechanisms a better opportunity to maintain bond rating levels during financial stress.

25   Mr. Hevert seems to rely on the fact that no bond rating agency has acted to raise

26   bond rating levels specifically as a result of the institution of a decoupling regime to

27   bolster his position that decoupling does not reduce risk. However, like Mr. Hevert's

27

[3] See, for example, Moody's quote provided by Mr. Hevert on page 44 of his testimony.

1   review of market price data for the group of four gas companies, there are many factors

2   that affect bond ratings, making the identification of any bond rating change for any one

3   particular factor problematic. For example, bond rating agencies review non-financial

4   operating criteria such as the nature of the market service territory in which the firm

5   operates, customer mix, the fuel or commodity supply, the operating efficiency,

6   regulatory treatment, management competency and the competition/monopoly balance in

7   the service territory. Bond rating agencies also review financial criteria such as interest

8   coverage, debt leverage, cash flow adequacy, construction risks, financial flexibility and

9   accounting accuracy. Moreover, they review those subjective and objective measures in

10   current as well as projected fashion in order that bond ratings have some predictive

11   quality for bondholders. Therefore, the fact that no bond rating agency has singled out

12   decoupling as *the* reason for a bond rating upgrade does not mean that decoupling does

13   not reduce utility company operating risk or that the lower risk imparted by decoupling

14   does not need to be recognized in the allowed return on equity capital.

15

16   **II. ADDITIONAL ISSUES RAISED BY MR. HEVERT AND MR. MOUL**

17

18   A. CURRENT FINANCIAL CONDITIONS AND THE COST OF EQUITY CAPITAL

19

20   Q. The first half of Mr. Hevert's testimony in this proceeding is devoted to the current

21   economic conditions in the aftermath of the recent "crisis" and the effect of those

22   conditions on the required return on equity. Do you concur that the economic crisis has

23   necessarily caused the cost of equity capital to increase?

24   A. No. My most recent cost of capital analysis for gas distributors was performed in

25   February of this year on behalf of the Office of the Attorney General of the

26   Commonwealth of Kentucky and submitted in a water utility base rate proceeding (the

27   gas utilities were used as one proxy group for the subject utility—Kentucky-American

1   Water).[4] My estimate of the cost of equity capital for the gas distributors in that

2   proceeding was in the range of 9.25% to 9.75%. I have not been retained to sponsor a

3   recommended return on equity analysis for Bay State Gas Company. However, my

4   recent analysis is pertinent in that it shows that an equity cost estimate range for gas

5   distribution companies in present market conditions is similar to the range for gas utilities

6   *prior* to the financial crisis.

7

8 Q. Other than the results of your own analysis, can you explain why the recent turmoil in the

9   capital markets does not indicate a significant shift in the cost of equity capital?

10 A. Yes. First, the cost of capital determined in a regulatory proceeding is <u>long-term</u> in

11   nature. That is why <u>long-term</u> sustainable growth rates are called for in the DCF model

12   when determining a regulated utility's cost of capital, and why <u>long-term</u> U.S. Treasury

13   bond yields are used in the regulatory application of the CAPM model. Also, the long-

14   term nature of cost of capital estimates matches the long-lived nature of utility assets.

15   While the dislocation in the credit markets of last Fall was certainly severe, and

16   unearthed technical risks in the financial system, those risks were aggressively addressed

17   by governments around the globe and the "credit freeze," which precipitated the

18   downturn, has begun to ease and is not expected to be a long-term condition.

19   Accordingly, the cost of equity is a long-term phenomenon but the credit crisis is not.

20   Second, while the difficulties in the financial system last Fall are not expected to

21   be permanent, the depth of the financial crisis did cause a shift in the outlook for the

22   economy and, thus, in investors' short-term market return expectations. What was

23   widely expected earlier in 2008 to be a U.S. economy in moderate recovery is now

24   expected to be one that will slowly recover from a one-year recession.[5] Negative or

25   anemic economic growth, of course, portends lower returns for the firms that comprise

26   the economy and lower return expectations for investors. The other primary factor in

26

[4] Kentucky-American Water Company, Case No. 2008-00427, Direct Testimony of Stephen G. Hill.
[5] See, for example, Value Line, *Selection & Opinion*, May 29, 2009, pp. 3505-3510.

1   investors' re-evaluation of the price they are willing to provide to buy stocks is the

2   realization of the extent to which the financial sector was over-leveraged and engaged,

3   without oversight, in financial practices that endangered the availability of credit. While

4   governments in the industrialized world have intervened to provide capital to both the

5   money-center banks and even directly to corporations, the new knowledge of the extent

6   to which the financial sector utilized leverage has raised investors' perceptions of the

7   potential volatility in the financial system. In short, the market's systematic risk is higher

8   today than investors previously understood it to be.

9

10   Q. How have these conditions affected equity markets?

11   A. The combination of these two factors, which imply lower expected returns (recession)

12   and higher systematic/non-diversifiable risk (financial sector leverage/credit crisis)

13   caused investors, en masse, to sharply re-value the prices they were wiling to pay for

14   stocks. Thus, the decline in stock prices is not due to higher return expectations by

15   investors or a higher cost of equity capital to corporations as Mr. Hevert argues. Rather,

16   given the current outlook for economic recession and decreased corporate earnings,

17   investors' return expectations are likely to be lower than they were before the credit crisis

18   and share prices have accordingly fallen to reflect those lower expectations.

19

20   Q. Are there other factors in current financial markets influencing the cost of equity capital?

21   A. Yes. Because long-term U.S. Treasury yields have declined during the financial crisis and

22   utility beta coefficients are lower because utility stocks have been less volatile than the

23   broader stock market, a Capital Asset Pricing Model (CAPM) analysis indicates a *lower*

24   cost of equity capital for utilities in the sample group selected by Mr. Moul as similar in

25   risk to Bay State Gas. According to the May 29, 2009 edition of Value Line, *Selection &*

26   *Opinion* (p. 3877), the recent yield on 30-year Treasury Bonds was 4.14%—40 basis

27   points *lower* than one year ago. Also the contemporaneous edition of Value Line's

28   *Summary & Index* indicates that the average beta coefficient of the companies in Mr.

1   Moul's similar-risk gas company group is currently 0.66. Combining those current data

2   with the long-term market risk premium published by Morningstar (6.50%)[6], would

3   produce a cost of equity estimate for Bay State of 8.43% [4.14% risk-free yield + 0.65 x

4   6.50% (market risk premium) = 8.43%]. That result is well below my current estimate of

5   the cost of equity, illustrating that there are certainly indications that the cost of equity

6   capital has not increased as a result of the financial crisis as Mr. Hevert claims.

7   Finally on this point, I note that I had occasion at the 41st annual Financial Forum

8   of the Society of Utility and Regulatory Financial Analysts (SURFA) in April of 2009 to

9   host a panel of speakers on the topic: "Estimating the Cost of Capital in Today's

10   Economic & Capital Market Environment." The speakers included an investment

11   manager for a $13 Billion state teacher's retirement fund, a bank vice-president, a senior

12   vice-president of Moody's, and a professor of finance at Georgetown University (where

13   the conference was held). The speaker's credentials and powerpoint presentations are

14   available on SURFA's website (www.surfa.com). The consensus of the panel was that

15   the recent financial crisis was not a long-term phenomenon and that long-term cost of

16   equity capital was largely unaffected by the economic slowdown in which the U.S.

17   economy now finds itself.

18   In summary, the recent downturn in stock prices in the marketplace does not

19   indicate that the cost of equity capital is markedly different from that based on relatively

20   steady-state market data prior to the recent financial crisis.

21

22   Q. In his testimony, Mr. Hevert points to a widening of yield spreads between utility debt

23   and U.S. Treasury securities. Doesn't that indicate an upswing in capital costs?

24   A. No. First, the level of long-term fixed-income capital costs represented by U.S. Treasury

25   bonds, which have been relatively moderate for several years, declined to new lows

26   during the uncertainty that existed last fall. More recently, as order is beginning to be

27   restored to the markets, the long-term Treasury rate has risen, but remains below levels

27

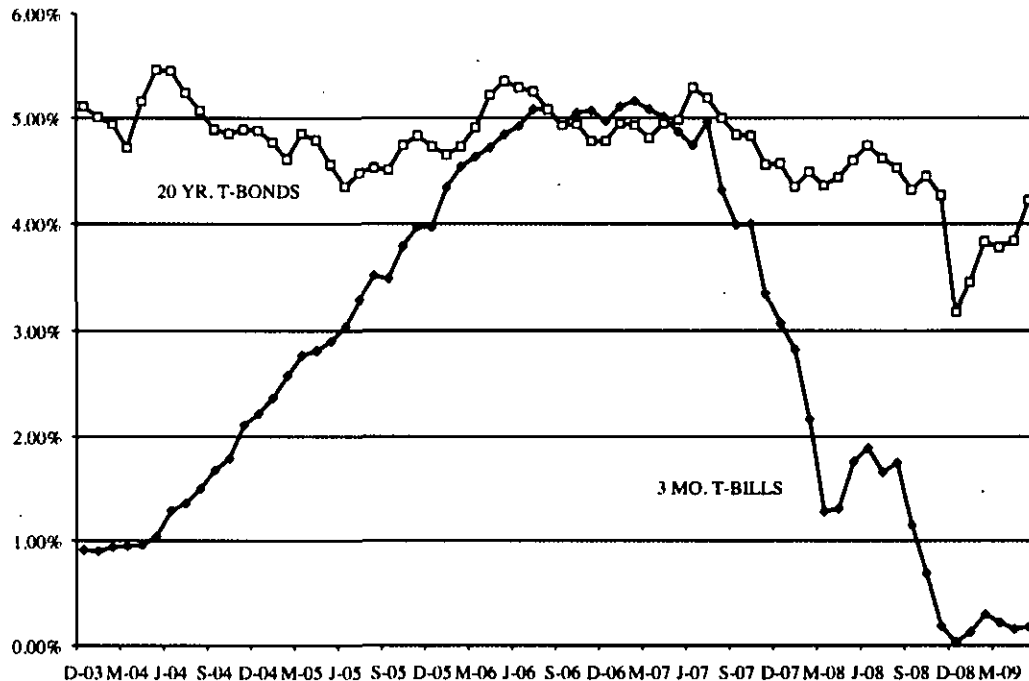[6] Morningstar, SBBI Valuation Edition, 2007 Yearbook, p. 28.

1   that existed pre-crisis. As shown in Chart V on the next page, although there were wide

2   fluctuations in *short-term* interest rate levels over the past five years as the Federal

3   Reserve Board (the Fed) raised and lowered the Federal Funds rate to slow down and

4   encourage (respectively) economic growth, long-term interest rates stayed in the range of

5   4.5% to 5.5% over most of that time, with a slow downward trend. However, as a result

6   of last Fall's market re-alignment and investors' preference for safe investments in the

7   face of uncertainty, long-term Treasury bond yields fell well below the lower end of that

8   historical range. According to the Federal Reserve Statistical Release H.15, the average

9   20-year T-Bond yield in December 2008 was 3.18%. Since that time, as I noted, as

10   markets have calmed and investors have begun to abandon the safe-haven, long-term

11   Treasury Bond yields have risen to about 4%.

12   In late 2008, the Fed also lowered short-term interest rates to near zero to lessen

13   the impact of the pending recession and increase the liquidity in the markets. With

14   liquidity still a concern, those short-term Treasury rates still remain low in order to

15   stimulate economic activity.

16

1

2   Chart IV

3   Recent Interest Rate Changes

D-03 M-04 J-04 S-04 D-04 M-05 J-05 S-05 D-05 M-06 J-06 S-06 D-06 M-07 J-07 S-07 D-07 M-08 J-08 S-08 D-08 M-09

4

5   Data from Federal Reserve Statistical Release H.15

6   Because the market for U.S. Treasury securities has remained liquid, it is

7   reasonable to believe that the yields on long-term Treasuries are representative of

8   investors' current risk-free return expectations. Therefore, this fundamental building

9   block of capital costs (the risk-free rate) provides an indication that in the current

10   economic environment, capital costs are lower.

11

12 Q. What about the market for investment-grade corporate debt?

13 A. Declining yields has not been the case with corporate bonds over the past few months.

14   Following the demise of Lehman Brothers and the devolution of the financial community

15   in the U.S. and abroad due to enormous debt obligations related to mortgage-back

16   securities and credit default swaps—even with the promise of government support of the

17   successor financial institutions—there was a lack of liquidity in that sector of the market.

1   The banks and investment brokerage firms were holding on to capital in order to shore up

2   their own balance sheets rather than re-injecting those monies into the financial system

3   through additional lending (i.e., buying corporate debt). As a result, even though the Fed

4   was driving down short-term Treasury rates to provide additional liquidity for the

5   economy in general, that liquidity was not reaching the corporate bond market and, with a

6   lack of capital supply, corporate bond yields increased, as shown in Chart VI, below.

7

8   Chart VI

9   Financial Crisis: Bond Yield Changes

10
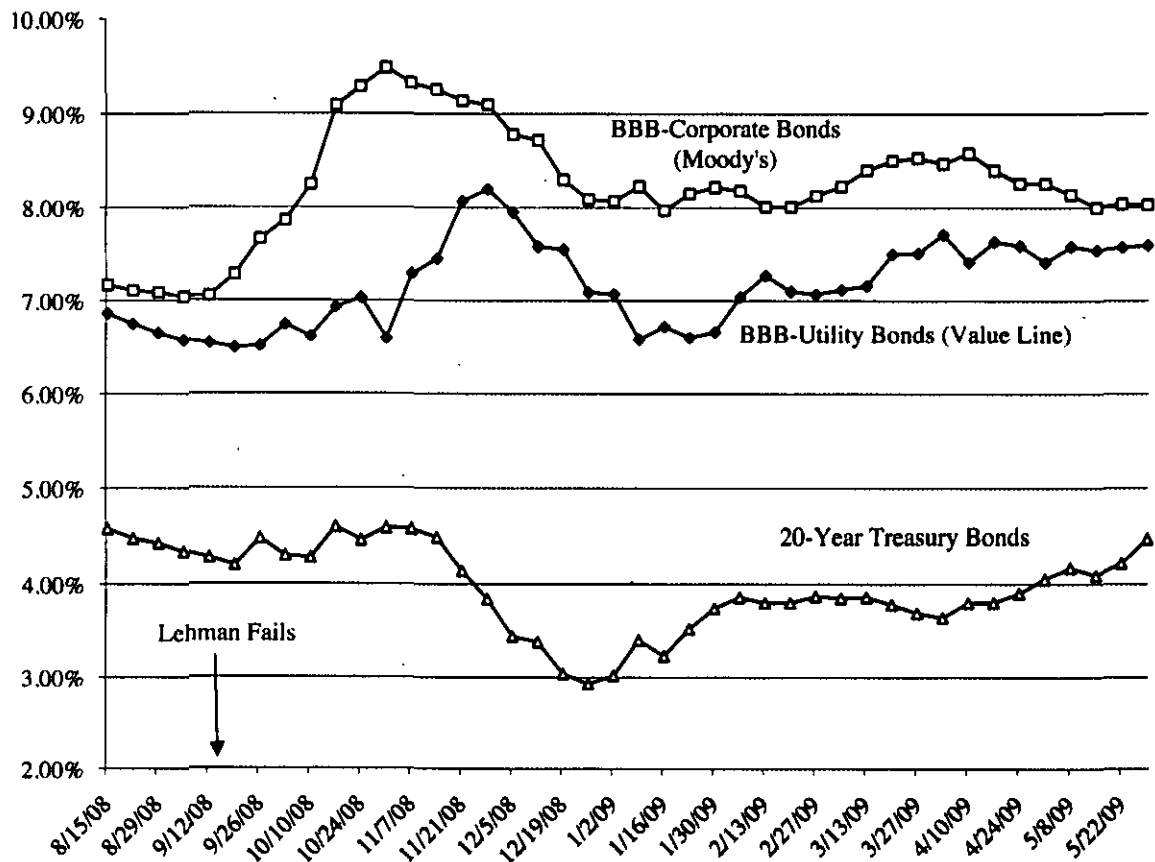
11   Following the failure of Lehman Brothers, as the full extent of the debt overhang

12   in the financial industry became known, BBB-rated corporate bond yields began to

1   increase, even as long-term Treasury yields remained relatively steady at about 4.5%.

2   According to Value Line *Selection & Opinion* (weekly editions from 8/15/08 through the

3   most recent available, 5/29/09), BBB-rated utility bond yields rose as well, but not to the

4   extent of corporate bonds due, it is reasonable to believe, to the lower risk of utilities. As

5   · the potential for economic collapse recedes, liquidity has been restored to the bond

6   markets, causing both corporate and utility bond yields to decline from their highs

7   reached at the end of 2008. Most recently, according to Value Line, utility bond yields

8   are about 50 basis points above their "pre-crisis" levels, while the corporate yields

9   reported by Moody's remain about 1% higher, although those yields are also declining.

10   Therefore, as can be seen in the above Chart, the increase in yield spreads to

11   which Mr. Hevert refers is not merely the result of higher yields for corporate bonds, but

12   also, lower yields for U.S. Treasury securities. Fundamental uncertainty in the financial

13   markets drove investors to safe-haven securities, lowering T-bond yields; and a lack of

14   liquidity in the corporate bond markets drove yields higher. However, the spike in yield

15   spreads peaked at the end of 2008/beginning of 2009 and has begun to trend toward pre-

16   crisis levels. It is not unreasonable to think of the financial crisis as a very, very large

17   stone thrown in the relatively calm pond of the financial markets, causing big waves

18   initially, but, with the passage of time, those waves diminish in size and the "pond"

19   returns to its normal state. In my view, the data above show in a graphical fashion, the

20   beginning of that return to normalcy.

21   On balance, then, the fixed-income data available in the market indicates that

22   while there were technical difficulties in the corporate bond market that drove up yields

23   for a period of time, it does not appear to be a long-term phenomenon and is, therefore,

24   unlikely to represent investors' long-term expectations. Those data also indicate that

25   investors' required return for a risk-free investment remains low by historical standards—

26   around 4%. Finally, the yield spreads between utility and corporate debt and U.S.

27   Treasury securities has begun to narrow, nearing the levels that existed prior to the

28   financial crisis and does not indicate the expected long-term increase in the cost of capital

1   implied in the testimony of Company witness Hevert.

2

3   B. COMMENTS ON MR. MOUL'S COST OF EQUITY ANALYSIS

4

5 Q. What equity return does Mr. Moul recommend in this proceeding?

6 A. Mr. Moul recommends that Bay State be awarded a return on common equity of 12.25%.

7

8 Q. In your opinion as a cost of capital expert, is Mr. Moul's equity return recommendation

9   above or below the Company's actual cost of equity capital?

10 A. While I have not performed a cost of capital analysis in this proceeding, my most recent

11   estimate of the cost of equity for gas distributors indicated a reasonable range of 9.25% to

12   9.75%. That analysis was performed in April of this year and, there has not been any

13   significant shift in capital costs since that time.

14   In addition, as shown in Chart VII below, the average opinion of regulators—

15   represented in return on equity decisions over the past few years as catalogued by Public

16   Utilities Fortnightly—is that utility cost of capital is about 200 basis points below the

17   level recommended by Mr. Moul (i.e., about 10.25% versus Mr. Moul's 12.25%). Chart

18   VII also shows that from 1996 through the end of 2008, the average allowed return for

19   electric and gas utilities in the U.S. has declined from just over 12% to just over 10%.

20   Also, Regulatory Research Associates reports that the average allowed return for gas

21   distributors in the first quarter of 2009 was 10.24%, on an average common equity ratio

22   of 44%.

23

1

2 Chart VII

3 Allowed Return on Common Equity

Data from Public Utilities Fortnightly

4

5
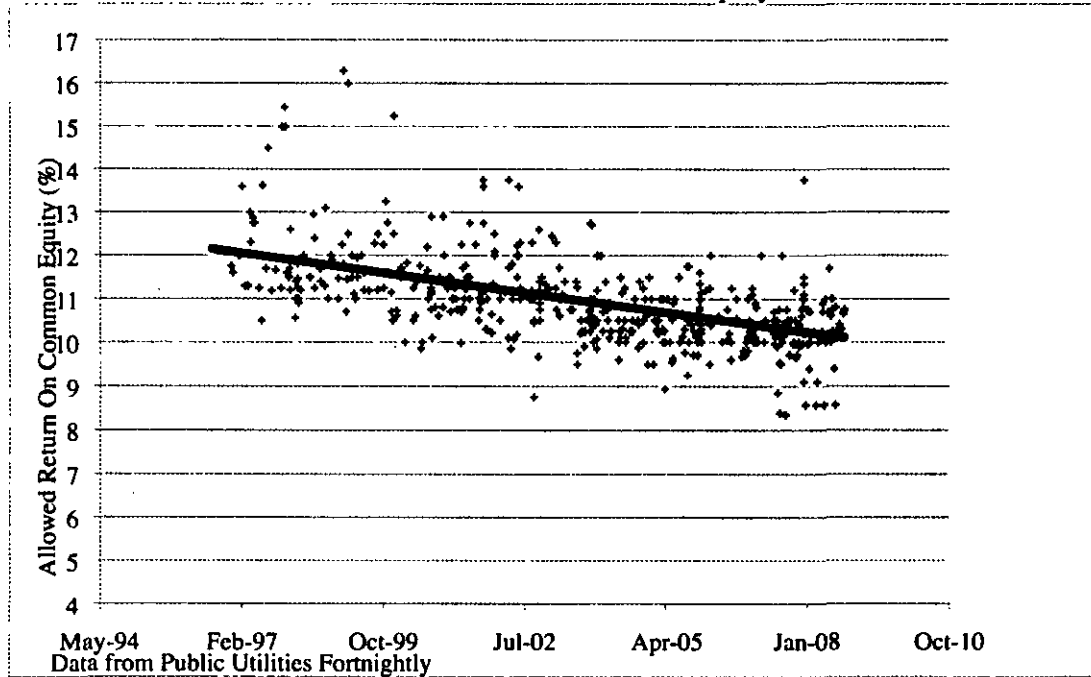
6   In my opinion, the average return on common equity for U.S. utilities allowed by

7 regulators still exceeds the current cost of equity capital, however the trend shown on

8 Chart VII is certainly in the right direction. Moreover, Mr. Moul's recommendation in

9 this proceeding is counter to that trend in lower allowed returns and, I believe,

10 significantly overstated.

11

12 Q. On what aspect of Mr. Moul's testimony, in particular, do you wish to comment, Mr.

13   Hill?

14 Q. Mr. Moul makes an improper adjustment to the market-based cost of equity to account

15   for what he characterizes as a "leverage" adjustment. That adjustment is without

16   theoretical foundation and serves only to inflate the recommended return. Mr. Moul's

17   adjustment to the cost of equity arises when the market-value capital structure of a utility

1   or a utility sample group shows a different mix of capital from the book value capital

2   structure of a utility or utility sample group. If the market value and the book value of

3   the common equity of the utility (or utility sample group) are the same (i.e., if they are

4   equal), then Mr. Moul's adjustment disappears—by his own definition there is no need

5   for an adjustment if the market price and book value of utility equity are equal.

6   Therefore, despite his protestations to the contrary (see Moul Direct, p. 30, 31), Mr.

7   Moul's "leverage" adjustment is really a market-to-book adjustment to the cost of equity

8   capital, which the Department correctly recognized and rejected in its prior rate order for

9   Bay State (D.T.E. 05-27, November 30, 2005).

10

11   Q. Just to be clear, when you use the terms "book value capital structure" and "market value

12   capital structure," what do you mean?

13   A. Book-value capital structures represent the actual mix of capital used by the firm. They

14   are calculated based on the dollar amount of each form of capital (common equity,

15   preferred stock, and long-term) actually appearing on the books (the balance sheet) of the

16   firm. The market-value capital structure is a percentage mix of capital in which the

17   amounts of capital are measured based on their market value.

18   The market value of common equity capital is the total dollar amount of equity

19   measured on a market value basis. It is calculated as the number of shares outstanding

20   times the current market price per share. The market value of debt is more difficult to

21   calculate. If the prevailing interest rates are lower (higher) than the coupon rate of a

22   firm's debt, the market value of that debt will be higher (lower) than the face amount.

23   That is, the market value of a thousand-dollar 7% bond will be higher than $1000 if the

24   prevailing interest rate for that type of security is lower than 7%, and vice versa.

25   However, unless current interest rates are very different from embedded debt costs, the

26   fair value of a firm's debt will approximate its book value. In any event the primary

27   factor that makes the market-value capital structure different from the book value capital

28   structure is the difference in the market price and book value of the company's common

1   equity.

2

3 Q. Can you provide a brief explanation of Mr. Moul's market-value capital structure logic?

4 A. Mr. Moul's position is that investors rely on market value capital structures, and a cost of

5   equity estimate (from DCF, CAPM, etc.) relates to the financial risks inherent in those

6   market-value capital structures. He testifies that if the cost of equity so derived is applied

7   to a utility book value capital structure that has less equity and more debt (and, therefore

8   he believes, more financial risk) than contained in the market-value capital structures of

9   the sample companies, the equity return will not be sufficient to satisfy investors, i.e., it

10   will be too low. Therefore, he makes an upward adjustment of 60 to 117 basis points to

11   "account" for the difference between market-value and book-value common equity ratios.

12

13 Q. When there are differences in market-value and book-value capital structures for a firm

14   or a type of firm, is Mr. Moul correct that there are there differences in financial risk?

15 A. No—that is the key assumption underpinning Mr. Moul's logic and it is a fundamental

16   flaw. Mr. Moul is making a theoretically improper comparison between market-value

17   capital structures and book-value capital structures in order to claim that a financial risk

18   difference exists. There is no theoretical support for that position.[7] While it can be

19   meaningful to compare one market-value capital structure to another market-value capital

20   structure or one book-value capital structure to another to assess comparative risk,

21   comparing the market-value capitalization to the book value capitalization of the same

22   firm or type of firms simply does not have theoretical meaning.

23   When utility common equity market prices are above book value, the capital

24   structure measured with market values will have a higher equity percentage and a lower

25   debt percentage than the capital structure measured with book value. That does not

---

25

[7] Mr. Moul cites Miller and Modigliani's work as support for his leverage adjustment. However, there is absolutely no mention of book-value capital structures in the work he cites and Miller and Modigliani clearly intend their adjustment to be used in "apples-to-apples" comparisons of, i.e., market-value capital structures to market-value capital structures. There is no support in the financial literature for any comparison on market-value to book value capital structures.

1   signify any difference whatsoever in financial risk. In his focus on market-value capital

2   structures, Company witness Moul is claiming that one firm or type of firm

3   simultaneously can have two levels of financial risk. This is not possible.

4

5   Q. Why is it impossible for one type of company to have two levels of financial risk?

6   A. There can be no "difference" in financial risk for one company or one type of company at

7   a given point in time, regardless of the relationship between market price and book value.

8   Yet, that is a basis for the Company's focus on market-value capital structure.

9   Financial risk, by definition, is a function of the degree to which interest

10   payments impact the volatility of a firm's income stream. As the dollar amount of interest

11   expense increases relative to the operating income available to pay debt service, the

12   volatility of the net income available to stockholders increases. That increase in the

13   volatility of the return creates more risk for the stockholders. It is the additional interest

14   expense associated with the firm's debt level that causes the increase in the volatility of

15   the income available to equity holders. This is a standard description of financial risk

16   found in textbooks.[8]

17   In other words, true financial risk is a function of the amount of fixed charges or

18   debt expense incurred by the firm and the impact of those fixed charges on the variability

19   of the income available to the stockholder. Therefore, when the actual amount of

20   borrowed funds increases, causing the dollar amount of fixed charges to increase,

21   financial risk increases. On that issue, all parties would agree.

22   Market-value capital structure and book-value capital structure are simply

23   different ways to express the amount of debt leverage in the capitalization of a company.

24   One measure uses the market value of the capital and one use the book values of the

25   capital. However, there is no difference in either the amount of debt or in the actual fixed

26   charges incurred by a firm whether one expresses the capital ratios with market values or

26

[8] See, for example, Brigham, E. F., Intermediate Financial Management, 5th Ed, 1996, Dryden Press, Fort Worth TX, pp. 361-364.

1   by using book values. The genesis of financial risk—the actual, contractual level of

2   interest expense—does not change. Because interest expense does not change, one

3   company (or group of companies) at one point in time cannot have two levels of financial

4   risk, no matter how the capital structure ratios are measured. That is because the amount

5   of fixed charges (the actual debt costs) does not change. Differences between market-

6   value and book-value capital structure cannot, therefore, reflect differences in financial

7   risk for one company or group of companies at any one point in time. Therefore, Mr.

8   Moul's position that an upward adjustment to the cost of equity capital is related to

9   financial risk differences that exist between market-value and book-value capital

10   structures is incorrect.

11

12   Q. Has Mr. Moul consistently used market-value capital structures in the past in his

13   determination of the return to be allowed utilities in rate base/rate of return proceedings

14   such as this one?

15   A. No. Mr. Moul has testified on the subject of the cost of equity for several decades but

16   prior to 1997 he made no adjustment to market-based cost of equity estimates (DCF,

17   CAPM and Risk Premium) to account for what he characterizes as risk differences in

18   leverage between market-value capital structures and book value capital structures.

19

20   Q. Is the use of market-value capital structures in theoretical finance a new theory that has

21   just begun to be implemented?

22   A. No. Capital structure theory in textbooks refers to market values, however, this has been

23   the case since the 1950s. In the ensuing sixty years, regulated utility rates have been

24   based on the cost of equity capital being applied to book-value capital structures and

25   during that time utilities have been able to attract the capital necessary to provide the

26   service required by the public. Moreover, during that time period (prior to 1997) Mr.

27   Moul also adjered to this industry-standard practice and applied equity costs directly to

28   utility book values, i.e., without any "leverage" adjustment.

1   The use of a book-value capital structure to determine the overall cost of capital in

2   traditional utility rate proceedings is a long-standing, nearly universal practice. Book-

3   value capital structure has long been used to determine the capital costs associated with a

4   depreciated original-cost rate base. The Hope decision changed the debate in regulation

5   from the value of utility rate base to the return to be allowed on that rate base, which was

6   to be the depreciated original cost, i.e. book value. Investors have been aware of that

7   regulatory practice and, through efficient markets, incorporate that understanding into the

8   stock prices they provide for utility equities.

9   Investors are also aware that capital structure data—whether obtained through the

10   Securities and Exchange Commission, regulatory bodies such as FERC, company annual

11   reports, bond rating agencies, or investor services available in hardcopy or on the

12   internet—is universally presented as *book* value, i.e., the capital values that appear on the

13   books of the company. Book value is the appropriate capital structure measure to use in

14   rate setting and equity capital costs determined in the market place do not have to be

15   adjusted to account for differences between market-value and book value capital

16   structures, as Mr. Moul's testimony in this proceeding incorrectly suggests.

17

18   Q. Mr. Moul notes that the Pennsylvania regulatory commission has adopted his leverage

19   adjustment. Have other regulatory bodies (in addition to Massachusetts) correctly

20   rejected that type of adjustment to the market-based cost of equity capital?

21   A. Yes. In its Report and Order in Docket No. ER-2007-0002, the Missouri Commission

22   rejected a market-value risk adjustment. In that proceeding the utility (AmerenUE) had

23   two equity capital witness, both of whom recommended an adjustment for financial risk

24   related to differences between the market-value capital structures of the sample

25   companies and the book value capital structures of the applicant. The Commission

26   stated:

27

28   "In large part, the overly high return on equity

29   recommendations put forward by AmerenUE's witnesses

1	result from their inclusion of a large financial risk add-on
2	premium, based on the allegedly greater financial risk
3	resulting from the market value of common equity in
4	AmerenUE's capital structure. The witnesses use this
5	premium adjustment to increase McShane's return on
6	equity recommendation by 100 basis points, and Vander
7	Weide's by 70 basis points. But despite his advocacy of an
8	adjustment to account for AmerenUE greater risk, Vander
9	Weide acknowledged at the hearing the AmerenUE's risk is
10	about average for the electric industry.
11	In addition to the obvious incongruity of a large risk
12	adjustment for a company with an average level of risk, the
13	opposing experts convincingly explained that the proposed
14	upward adjustment for financial risk was inappropriate for
15	more technical reasons as well." Missouri Public Service
16	Commission, Case No, ER-2007-0002, Report and Order,
17	May 22, 2007, p. 40.
18	

Also, in response to a ratemaking proposal that considered market-value capital structures, the West Virginia Public Service Commission strongly rejected the use of market values to determine rates. That Commission saw a recommended adjustment to the cost of equity based on market values as an attempt to supplant original cost rate base regulation with fair value rate base regulation, which is illegal in that state. Mr. Moul was the cost of capital witness in that case.

26	"Additional examples of the Company witness raising his
27	sights above what a reasonable analysis produces can be
28	found in the market value adjustments that he makes. His
29	water group DCF analysis would be only 8.98%; however,
30	he leverages this number up by 54 basis points, or .54%, to
31	reflect the fact that stockholders pay market prices for stock
32	and those market prices may exceed the book value of a
33	utility's rate base. Thus, the Company asks us to effectively
34	depart from our long-standing use of an original cost rate
35	base. We could do this by simply applying the derived rate
36	of return, before market price leveraging, to an inflated rate
37	base that exceeds book value or, in the alternative chosen
38	by the Company, we can continue to use original cost rate
39	base and apply an inflated rate of return to that rate base."
40	(W.V.P.S.C. Case No. 03-0353-W-42T, West Virginia-
41	American Water Works, January 2, 2004, p. 18.)

1

2   Therefore, as the West Virginia Commission correctly notes, the use of market-

3   value capital structures as a basis for ratemaking turns the concept of depreciated original

4   cost ratemaking on its head. From an economic point of view, a market-value capital

5   structure is more closely related to a "fair value" measure of the utility plant. A market-

6   value capital structure is, by definition, the value the market puts on the capital invested

7   in the firm, based on current market conditions and expectations. In that way, it can be

8   said to represent the "fair value" of the company's utility investments in today's

9   marketplace. Mr. Moul states at page 12 of his Appendix E that his market-based capital

10   structure is a direct measure of the "Fair Value" of the companies in his gas utility sample

11   group. As the West Virginia P.S.C. held, the use of market-value capital structures to

12   determine the overall return that should be applied to book-value rate base is, effectively,

13   an attempt to circumvent original cost rate base regulation. That Commission rejected

14   Mr. Moul's "leverage" adjustment to the cost of equity.

15

16   Q. Does this conclude your discussion of Mr. Moul's "leverage" adjustment to account for

17   the difference between market and book value capital structures?

18   A. Yes. The use of market-value capital structures to determine the overall cost of capital to

19   be applied in rate base/rate of return proceedings is incorrect on both theoretical and

20   logical grounds, diverges from long-standing utility practice, would unnecessarily inflate

21   allowed returns above the cost of equity capital if implemented, and should, once again,

22   be rejected by the Department.

23

24   Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, MR. HILL?

25   A. Yes, it does.

EDUCATION AND EMPLOYMENT HISTORY
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.
"Private Equity Buyouts of Public Utilities: Preparation for Regulators," National Regulatory Research Institute, Paper 07-11, December 2007.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

BAY STATE GAS COMPANY

ANNUAL NET REVENUE VOLATILITY ANALYSIS

Year	Net Revenues [000] Y	Heating Degree Days X2	Massachusetts Gross State Prod. X1
1999	$155,035	5983	255,189
2000	$165,205	6162	274,949
2001	$170,172	6164	276,634
2002	$171,242	6270	274,997
2003	$187,398	7032	280,881
2004	$186,593	6795	286,541
2005	$205,531	6767	289,869
2006	$178,893	5848	297,634
2007	$206,994	6499	306,503
2008	$209,232	6368	312,476

	X1	X2	Intercept
Coefficients	0.881955061	19.89528844	-195335.9682
Std. Error	0.124550071	5.530182878	44578.29126
R-squared	0.916927222	6179.954928	#N/A
F-statistic	38.63173155	7	#N/A
T-statistic	7.081128522	3.597582374	-4.381863071

Data from Annual Reports filed by BSGC with the D.P.U. and Company responses to AG-19-1 and 19-2.
Massachusetts GSP from U.S. Bureau of Economic Analysis (www.bea.gov/regional/gsp).
Regression Model: Excel 2008 Analysis Pack (LINEST function). Value in "X2" column, on "R-squared" line
is the standard error of the dependent variable, and in that column, the value on the "F-statistic" line is the degrees
of freedom in the regresson.

BAY STATE GAS COMPANY

QUARTERLY NET REVENUE VOLATILITY ANALYSIS

Date	Net Revenues [000] Y	Heating Degree Days X3	Percent Unemployment X2	Seasonal Index X1
3/31/02	$61,539	3656	4.965%	1
6/30/02	$27,393	1065	5.207%	0
9/30/02	$20,825	84	5.410%	0
12/31/02	$63,081	2438	5.569%	1
3/31/03	$70,801	3656	5.763%	1
6/30/03	$34,577	1065	5.861%	0
9/30/03	$29,720	83	5.852%	0
12/31/03	$55,814	2227	5.731%	1
3/31/04	$79,026	3541	5.536%	1
6/30/04	$31,596	825	5.295%	0
9/30/04	$21,305	122	5.113%	0
12/31/04	$58,690	2307	4.979%	1
3/31/05	$81,345	3495	4.930%	1
6/30/05	$34,982	959	4.821%	0
9/30/05	$21,894	72	4.793%	0
12/31/05	$72,632	2240	4.829%	1
3/31/06	$74,106	2994	4.808%	1
6/30/06	$33,715	843	4.790%	0
9/30/06	$25,628	137	4.771%	0
12/31/06	$51,531	1874	4.713%	1
3/31/07	$85,977	3337	4.581%	1
6/30/07	$38,471	897	4.474%	0
9/30/07	$26,940	63	4.404%	0
12/31/07	$62,561	2202	4.455%	1
3/31/08	$88,218	3142	4.631%	1
6/30/08	$36,843	791	4.939%	0
9/30/08	$26,599	112	5.396%	0
12/31/08	$63,025	2323	6.087%	1

|	X1	X2	X3	Intercept
Coefficient	13679.92431	-421633.9861	11.39590665	44945.73287
Std. Error	5951.276376	264982.4977	2.343774221	13606.22375
R-squared	0.921953367	6568.351528	#N/A	#N/A
F-statistic	94.50281982	24	#N/A	#N/A
T-statistic	2.298653843	-1.591176737	4.862203256	3.303321604

Data from Company responses to AG-19-1 and 19-2.
Unemployment data from U.S. Bureau of Labor Statistics (www.bls.gov/data/).
Regression Model: Excel 2008 Analysis Pack (LINEST function). Value in "X2" column, on "R-squared" line
is the standard error of the dependent variable, and in that column, the value on the "F-statistic" line is the degrees
of freedom in the regresson.

BAY STATE GAS COMPANY

Annual Net Revenue Volatiltiy
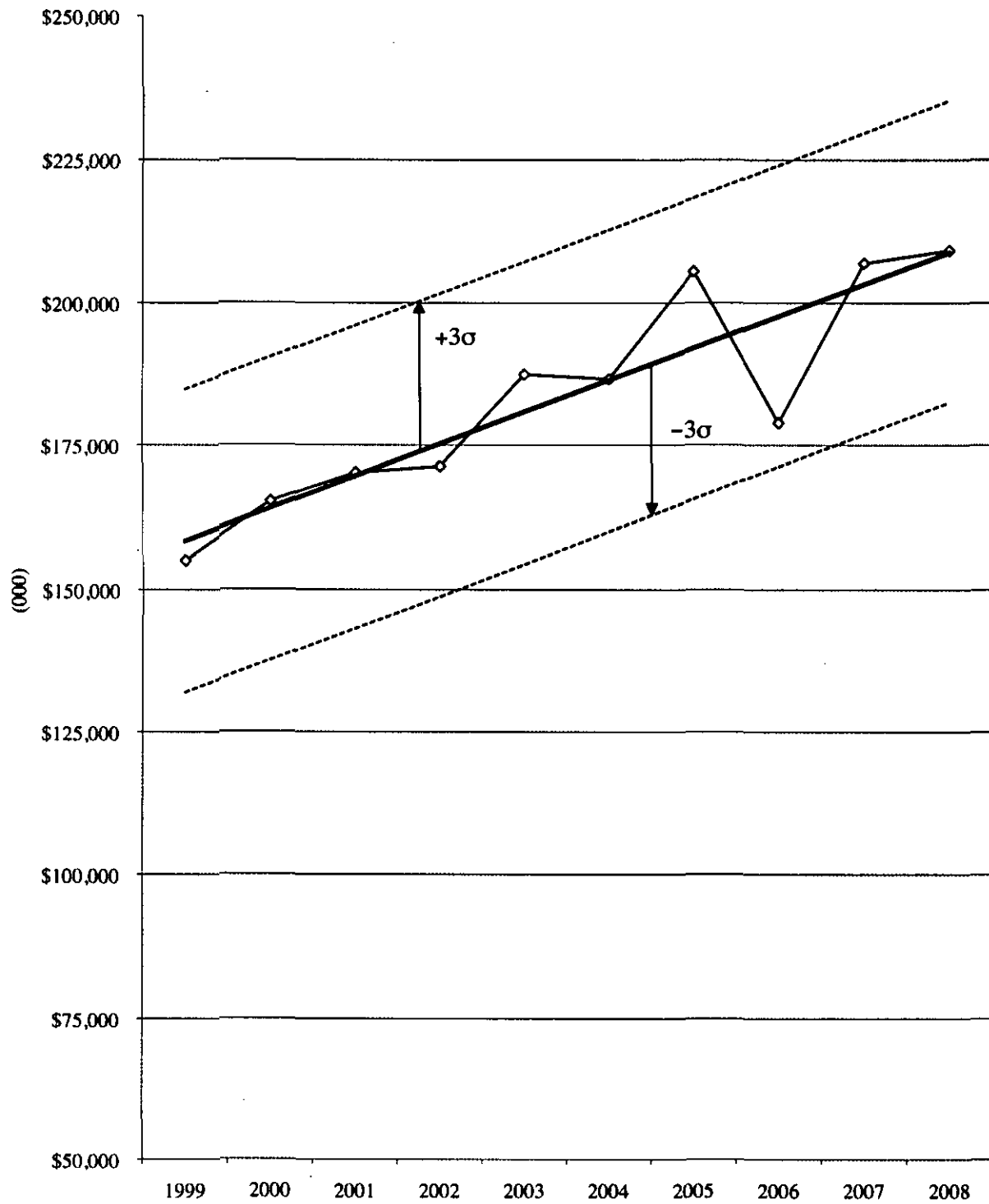
All data from Annual Reports to D.P.U.

BAY STATE GAS COMPANY

Quarterly Net Revenue Volatility

$140,000

$120,000

$100,000

+3σ

$80,000

$60,000

(000)

$40,000

$20,000

$0

−3σ

-$20,000

-$40,000

Mar-02 Jul-02 Nov-02 Mar-03 Jul-03 Nov-03 Mar-04 Jul-04 Nov-04 Mar-05 Jul-05 Nov-05 Mar-06 Jul-06 Nov-06 Mar-07 Jul-07 Nov-07 Mar-08 Jul-08 Nov-08
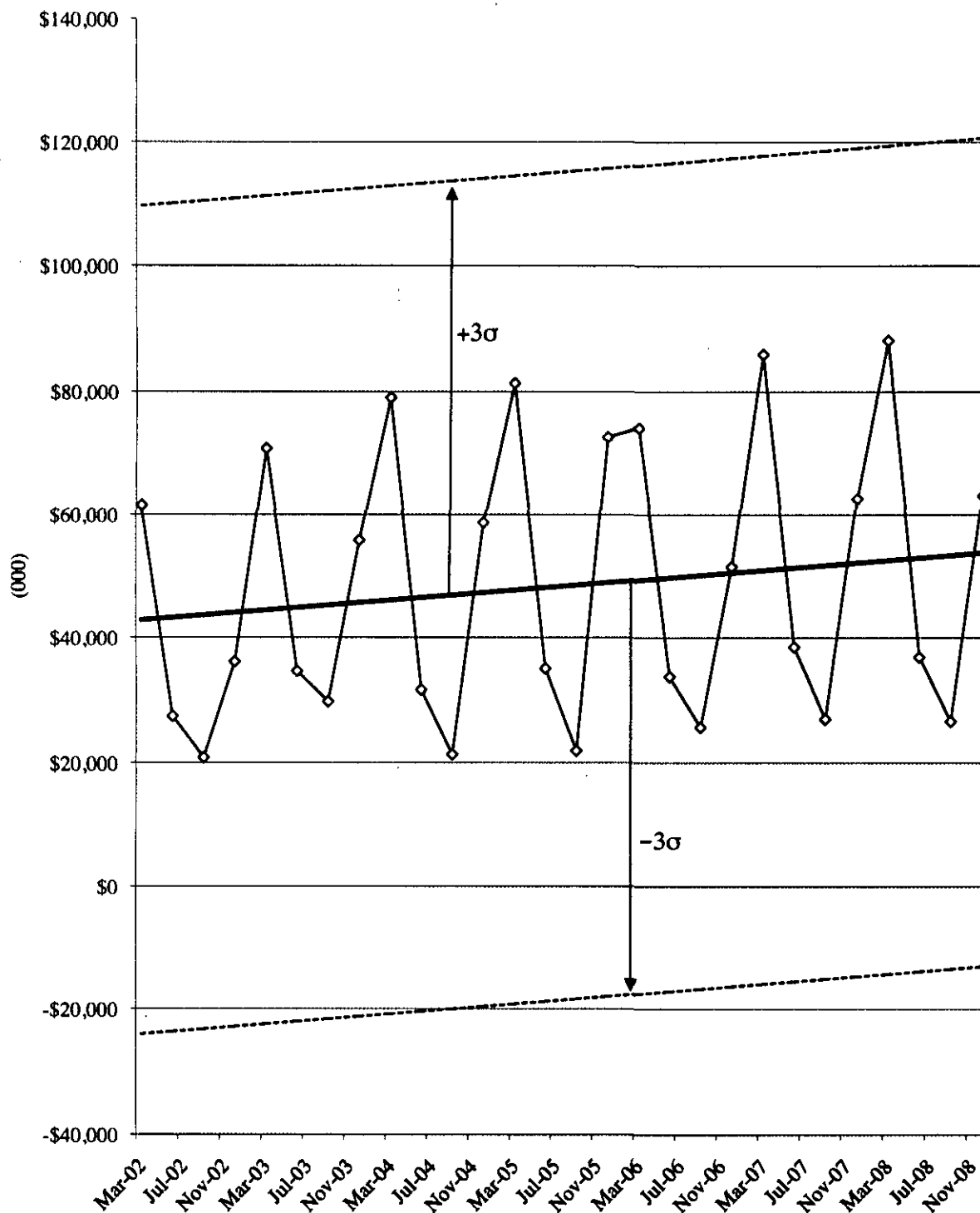
All data from Company response to AG-19-1.

BAY STATE GAS COMPANY

VARIANCE ANALYSIS

Year	X	Y Net Revenues [000]	x X-Xavg.	y Y-Yavg	x-squared	xy	y-squared
1999	1	$155,035	-4.5	-$28,594	$20	$128,675.24	$817,645,252.96
2000	2	$165,205	-3.5	-$18,425	$12	$64,487.29	$339,478,373.47
2001	3	$170,172	-2.5	-$13,458	$6	$33,644.65	$181,114,020.00
2002	4	$171,242	-1.5	-$12,387	$2	$18,580.68	$153,440,813.74
2003	5	$187,398	-0.5	$3,769	$0	-$1,884.42	$14,204,178.31
2004	6	$186,593	0.5	$2,964	$0	$1,481.90	$8,784,111.03
2005	7	$205,531	1.5	$21,902	$2	$32,852.67	$479,687,840.14
2006	8	$178,893	2.5	-$4,737	$6	-$11,842.26	$22,438,249.08
2007	9	$206,994	3.5	$23,364	$12	$81,774.77	$545,886,827.61
2008	10	$209,232	4.5	$25,603	$20	$115,212.06	$655,497,279.51
Sum	55	$1,836,295			$83	$462,983	$3,218,176,946
Average	5.5	$183,630					

slope (b) = (Σxy)/(Σ x-squared) = $5,611.91
intercept (a) = Yavg. - (b)Xavg. = $152,764.03
r-squared = (b)(Σxy)/(Σ y-squared) =   0.807356678

		50% of Variance
variance of y given x = (1/n-2)(Σ y-squared - bΣxy) =	$77,495,037.10	$38,747,518.55
standard deviation of y given x = (variance)$^{1/2}$ =	$8,803.13	$6,224.75
3 standard deviation units = S.D. x 3 =	$26,409.38	$18,674.25

Year	Actual Net Revenues [000]	Predicted Net Revenues [000]	+3σ [000]	-3σ [000]
1999	$155,035	$158,376	$181,444	$128,626
2000	$165,205	$163,988	$191,614	$138,795
2001	$170,172	$169,600	$196,581	$143,762
2002	$171,242	$175,212	$197,652	$144,833
2003	$187,398	$180,824	$213,808	$160,989
2004	$186,593	$186,435	$213,003	$160,184
2005	$205,531	$192,047	$231,941	$179,122
2006	$178,893	$197,659	$205,302	$152,483
2007	$206,994	$203,271	$233,403	$180,584
2008	$209,232	$208,883	$235,642	$182,823

Reference: Statistical Inference for Management and Economics, Hemtoberger, et al, Allyn and Bacon, 1975, pp. 284-287.

BAY STATE GAS COMPANY

NET REVENUE IMPACT OF RISK REDUCTION
1999-2008

Assume: With Decoupling, Historical Net Revenue Variance Reduced 50%

1) Standard Devition of Annual Revenues (from Schedule 3)

$\sigma = \$8,803$		σ = one standard deviation unit (historical)
$3\sigma = \$26,409$		3σ = 3 standard deviation units (historical)
$3\sigma* = \$18,674 =$	2.1213σ	$3\sigma*$ = 3 standard deviation units (50% variance)

2) Probability (p) Difference in Negative Outcomes Between 3 Standard Deviation Units (Historical), and
3 Standard Deviation Units (Variance Reduced 50%)

$p(3\sigma)$ =	0.49865
less $p(3\sigma*, 2.1213\sigma)$ =	0.48304
	0.01561 or 1.561% of average

3) Basis Point Impact of 1.561% Reduction in Average Annual Net Revenues

a) Average Annual Revenues 1999-2008 = $183.629 Million
                                                                      x .01561
                      Annual Net Revenue Reduction = $2.87 Million

b) Average Rate Base Estimate = $375.0 Million
   Average Common Equity Ratio Estimate = 53.0%
   Then, a 1% Equity Return Reduction Produces A Revenue Reduction Of:
                = (1% x 53.0% x $375 M)/(1-35% Tax Rate), or
                = $3.06 Million

c) If a 1% Equity Return Reduction Reduces Annual Revenues $3.06 Million,
   Then, A $2.87 Million reduction = 0.94% or 94 Basis Points

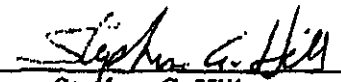# COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Bay State Gas Company   )   D.P.U. 09-30
)

AFFIDAVIT OF STEPHEN G. HILL

Stephen G. Hill does hereby depose and say as follows:

1.   I, Stephen G. Hill, on behalf of the Massachusetts Attorney General's Office, certify

that the testimony listed below, which bears my name was prepared by me or under

my supervision and is true and accurate to the best of my knowledge and belief.

Accordingly, Testimony of Stephen G. Hill. Signed under the pains and penalties of

perjury this 30th day of June, 2009.

_____
Stephen G. Hill